Power-to-gas

Short term and long term opportunities to leverage synergies between the electricity and transport sectors through power-to-hydrogen

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ABSTRACT

- In this study by environmental expert consultancies Hinicio and LBST for the Tuck Foundation scientific program « Future of Energy », two power-to-gas applications are presented: green hydrogen for use in refinery processes and the implementation of a semi-centralised power-to-hydrogen system supporting local hydrogen mobility.
- The two hydrogen applications have been analysed – the depth of analysis depends on the power-to-hydrogen application – regarding their contributions to greenhouse gas emission reductions, energy efforts, specific costs, and cumulated investments.
- Furthermore, sensitivities have been tested given the uncertainty of future regulatory conditions. Strategic implications are discussed for the short to mid-term deployment of power-to-gas technologies and recommendations derived to this end.

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Acronyms & Abbreviations

AFID	EU Alternative Fuels Infrastructure Directive
API	Unit to measure the crude-oil gravity
BEV	Battery Electric Vehicle
BImSchG/V	Federal Immission Protection Law/Ordinances ("Bundes-Immissionsschutzgesetz")
CGH_2	Compressed Gaseous Hydrogen
CH_4	Methane
CO_{2eq}	Carbon dioxide equivalents
CPT	Clean Power for Transport (EU strategy)
EEG	Renewable Energy Law "Erneuerbare-Energien-Gesetz"
FCEV	Fuel Cell Electric Vehicle
FCC	Fluid Catalytic Cracking
FQD	EU Fuel Quality Directive
GHG	Greenhouse Gas
GoO	Guarantees of Origin
H_2	Hydrogen
HFO	Heavy Fuel Oil
ICE	Internal Combustion Engine Vehicle
LBST	Ludwig-Bölkow-Systemtechnik
LCA	Life-Cycle Assessment
LHV	Lower heating value
LTE	Loi de Transition Energétique
NG	Natural Gas
PtG	Power-to-Gas (synthesised hydrogen/methane)
PtL	Power-to-Liquid (synthesised methanol, gasoline, kerosene, diesel)
RED	EU Renewable Energy Directive
SMR	Steam Methane Reforming
SNBC	Stratégie Nationale Bas Carbone
TWh	Terawatt hours
WtT	Well-to-Tank
WtW	Well-to-Wheel
yr	Year

Executive Summary

As part of its research program "The future of energy: leading the change", Fondation Tuck sponsored a study performed jointly by Hinicio and LBST between September and December 2015 which evaluates the technical and economic potential of power-to-gas technologies.

Coupling the electricity sector to the gas, mobility and industry sectors; power-to-gas is viewed by many experts as key in a future energy system characterised by a large share of intermittent wind and solar energy generation.

Indeed, power-to-gas provides a route for channelling substantial amounts of renewable energy to sectors that have been, until now, dependent on fossil energy sources - as required for meeting adopted climate goals. Power-to-gas also introduces a systemic flexibility resource which can, once implemented at large scale, significantly improves the operating conditions of needed dispatchable power generation by reducing the magnitude of load variations related to changing weather, while also decreasing curtailment of wind or solar power generation.

Furthermore, Power-to-gas can help maintain local balance between power generation and consumption where distributed power generation is added to the distribution grid, hence allowing to avoid power grid expansion for absorbing excess production.

The main condition for realising this potential is deployment ramp-up and continued scale-up. It is therefore essential to identify particular applications and associated conditions of implementation where this deployment could be market-driven already in the short term, considering also the policy environment.

Two particular applications have been identified and studied in order to evaluate their potential for supporting this power-to-gas technology ramp-up, considering in particular the framework conditions in France and in Germany respectively.

Green hydrogen in refineries is a promising means to reduce the greenhouse gas emission intensity of established transportation fuels in the short term, and a potential option to meet the requirements of the EU Fuel Quality Directive. In a scenario for France and Germany, it was assumed that the refineries' net hydrogen demand – today typically provided via steam methane reforming of natural gas – is to be supplied from green hydrogen from renewable electricity via water electrolysis by 2025.

With this process, a typical French and German refinery can reduce its greenhouse gas emissions 'gate-to-gate' by 14.1% and 7.2% respectively compared to today. In absolute terms, this is equivalent to the reduction of 1.33 and 1.50 million tons of CO_{2eq} per year with just 20 refineries, making this option highly effective. Indeed, this is a significant contribution to the ~10 Mt/yr CO_{2eq} emissions reduction that needs to be achieved in 2020 versus today to comply with the EU Fuel Quality Directive both in France and in Germany.

Full cost assessments show that green hydrogen in refineries is cost-efficient with greenhouse gas mitigation costs below German infringement costs and in the range of or even below other measures in transportation. Furthermore, it can be implemented in the short-term, because bulk quantities of hydrogen are already used in refineries, there is a track record in France and Germany with regard to the deployment of renewable power plants, and both countries have strong industry players in the electrolyser and hydrogen value chain.

From a wider perspective, bulk green hydrogen demand from refineries is of high strategic importance. Activating the electrolyser cost reduction potentials through capacity and learning-curve effects from the deployment of 1600 MW_e (France) and 1800 MW_e (Germany) cumulated electrolyser capacity entails long-term benefits for all power-to-gas and power-to-liquid applications that are needed for the energy transition. In line with the 'polluter pays principle', the cost burden to get the electrolysis technology through the economic 'valley of death' is shared among many fuel users with a knock-on effect on the fuel sales prices in the order of 0.8 and 0.5 cent per litre of diesel equivalent in France and Germany respectively.

To pave the way for green hydrogen use in refineries, it is **recommended** to:

- Adapt the EU Fuel Quality Directive and national regulatory frameworks to facilitate and encourage green hydrogen use in refineries;
- Improve the data basis on hydrogen use in refineries through further research activities; and
- Support business case analyses for individual refineries and regional roadmaps for renewable power and hydrogen infrastructure deployment.

Semi-centralised power-to-hydrogen systems could become an effective and economically viable way of developing the supply of renewable or low-carbon hydrogen to emerging fuel cell electric vehicle (FCEV) fleets with co-benefits for the local energy system by facilitating the integration of renewables and enhancing local energy autonomy and strengthening the local economy.

These systems combine electrolysers at MW scale with means of distribution of compressed hydrogen to nearby points of utilisation, such as hydrogen refuelling stations or industrial facilities consuming hydrogen. Addressing the needs of multiple points of hydrogen consumption with a single hydrogen production plant provides economies of scale while facilitating the provision of grid services. Furthermore, the location of the unit can be chosen for maximization of operational management synergies with other industrial activities and for optimal interfacing with the power and natural gas grids. This set-up, which can be implemented with the current technology offer, allows the provision of multiple energy services resulting in the combination of complementary revenue streams. Combining multiple revenue streams is a key condition of economic balance and financial risk management, as the delay in local hydrogen demand ramp-up for mobility applications is typically a key hurdle to overcome.

Starting from a reference set of hypotheses (on electricity prices, technology costs etc.), and examining different variations, the following **conclusions** can be drawn from the techno-economic analysis of the semi-centralised power-to-hydrogen system:

- Assuming the application of a certain number of favourable regulatory conditions which are considered defendable[1], achieving economic balance seems feasible for short-term deployments in France; therefore, with some further support -for instance in the form of investment subsidies- such deployments could attract private investment.
- The French fee regime (as applied in this study) would be particularly favourable for Power-to-gas. In contrast, the grid fee regime currently applied in Germany handicaps Power-to-gas. In the short-term, the study concludes that the economics of Power-to-gas are therefore more attractive in France rather than in Germany.
- Injection into the natural gas grid can generate two complementary revenue streams – from sales to the gas grid, and from services to the power grid performed when injection is taking place - which reduces exposure to uncertainty of revenues from the hydrogen market.
- A potentially attractive alternative to purchasing the needed electricity on the spot market is to contract its supply directly from a renewable power producer. Since consumption would take place only when this electricity has the lowest market value (i.e. during the hours for which the spot market prices are typically extremely low), the producer could accept a high level of discount for supply under such conditions, in return of visibility on the sales price. In the short term, a power-to-hydrogen system could afford to pay 30% of the full cost of renewable electricity under such a scheme. Taking into account technological improvements[2] and cost reduction of power-to-hydrogen and power generation from renewables expected by 2030, a power-to-hydrogen system could afford to pay the full average cost of renewable electricity (although it would only be consuming it in absence of strain on demand).
- The study shows that an economic balance could potentially be achieved without public financial support by 2030 in both the French and German market environments thanks to technological improvements.

For the development of power-to-gas as a key component in energy transition, the study authors **recommend** to:

- Create a feed-in tariff for the injection of green or low-carbon hydrogen into the natural gas grid of a level comparable to that of biomethane in France;
- In France, grant the hyperélectro-intensif status to hydrogen power-to-gas production;
- In Germany, provide similar tax, EEG appropriation, and grid fee benefits to hydrogen production by electrolysis as the hyperélectro-intensif status;
- In Europe, further develop sustainability criteria, certification procedures and accountability of green or low-carbon hydrogen towards EU targets, especially

[1] Exemption of grid fees and taxes for the electricity used to produce low-carbon hydrogen that is injected into the natural gas grid, a feed-in-tariff comparable to that applied to biomethane, and application of the conditions (exemption of grid fees) that are applicable to "electro-intensive" facilities.

[2] These technological improvements are an increase in electrolyser efficiency, the extension of stack lifetime and the reduction of electrolyser capital costs.

with regard to the EU Renewable Energies Directive (RED) and the EU Fuel Quality Directive (FQD);

- Exempt electricity used to produce green or low-carbon hydrogen injected into the natural gas grid from grid fees and energy taxes;
- Financially support the implementation of supplying hydrogen to fuel cell electric vehicles.

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1 BACKGROUND, OBJECTIVES AND APPROACH

As part of its research program "The future of energy: leading the change", the Fondation Tuck is sponsoring a project to evaluate the Technical and Economic potential of power-to-gas technologies (Topic 2).

As set in the call, the project aims to address the core question: "Is the conversion of surplus electricity to gas a technologically and economically feasible option to mitigating intermittency?"

Generally, power-to-gas technically allows for the coupling of hitherto largely unconnected energy sectors by converting electricity into a chemical energy carrier. In this study, we plan to assess potential opportunities to address intermittency by leveraging synergies between the electricity, the transport and industry sectors through the use of power-to-gas technology whilst taking technical and economic dimensions into account.

Current investments in power-to-gas technologies face the challenge of low hydrogen prices. When injecting the resulting gas into the gas grid or when using it as a feedstock for industry, achievable prices are essentially set by the natural gas price. Marketing hydrogen as a future fuel in the mobility sector would in principle allow for higher prices, but the number of fuel cell vehicles is still very small and will grow only slowly in the coming years. On the other hand, the potential coupling of the electricity sector to the gas, mobility and industry sectors provided by power-to-gas is viewed by many experts as one of the key technologies in a future energy system characterised by a large share of intermittent wind and solar energy generation. To properly prepare for the future today, it is vital to analyse potential applications and identify complementary revenue streams allowing for an early economically balanced operation of power-to-gas installations. In this study, such opportunities are discussed along with requirements on the market, technology, and policy environments.

In doing so, this study will focus on two applications targeting an eventual use of power-to-gas in the transport sector in the short-term:

The study was structured into three Work Packages (WP), each comprising a set of tasks as shown in Figure 1 and described in greater detail below:

- WP 1: Setting the Scene.
- WP 2: Detailed analysis and comparison of selected power-to-gas applications for France and Germany.
- WP 3: Roadmap considerations and policy recommendations at national and EU level.

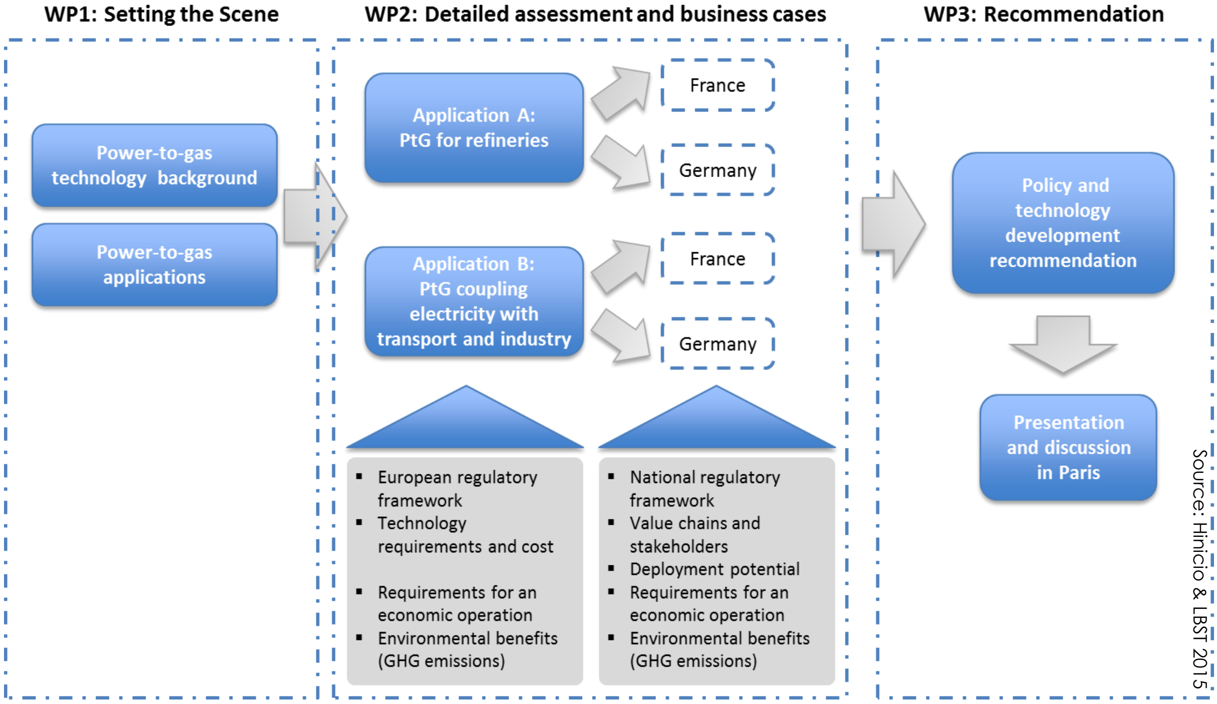


Figure 1: Methodology

Application A: **The possibilities to use large amounts of green hydrogen, derived from power-to-gas, in refineries** producing transport fuels, thereby reducing the specific greenhouse gas emissions of the resulting fuels and offering significant potential to address intermittency by an adaptive operation of the power-to-gas plants is evaluated.

Application B: **The implementation of a semi-centralised power-to-hydrogen system supporting the deployment of fuel cell electric vehicles** is evaluated, with a focus on the associated business case.

In analysing these applications, we will compare situations in France and Germany, two nations driving the change in the European energy sector where power-to-gas applications are poised to grow in the near future but with different backgrounds and contexts. For both applications, we will look into the regulatory framework at a national and European level, into technology requirements and costs, and the corresponding environmental performance with a focus on greenhouse gas (GHG) emissions[3]. On this basis, we will outline requirements for an economic operation of power-to-gas plants and provide recommendations targeting further development of policies and technologies.

[3] Analogous to [JEC 2014] the energy use and associated greenhouse gas emissions from the manufacture of power plants, steam methane reformers, electrolysers, refineries, etc., and vehicles for the distribution of the final fuel has not been taken into account.

2 Setting the Scene

This section provides an overview of power-to-gas introducing:

- the technologies involved and associated levels of maturity and costs;
- their main application fields.

This will provide a technological, economic and environmental background for the discussions in the subsequent sections.

Power-to-Gas designates the production of a high energy density gas from electricity via water electrolysis, constituting a subcategory of the conversion of electrical power into another form of energy or into a chemical, as shown in Figure 2.

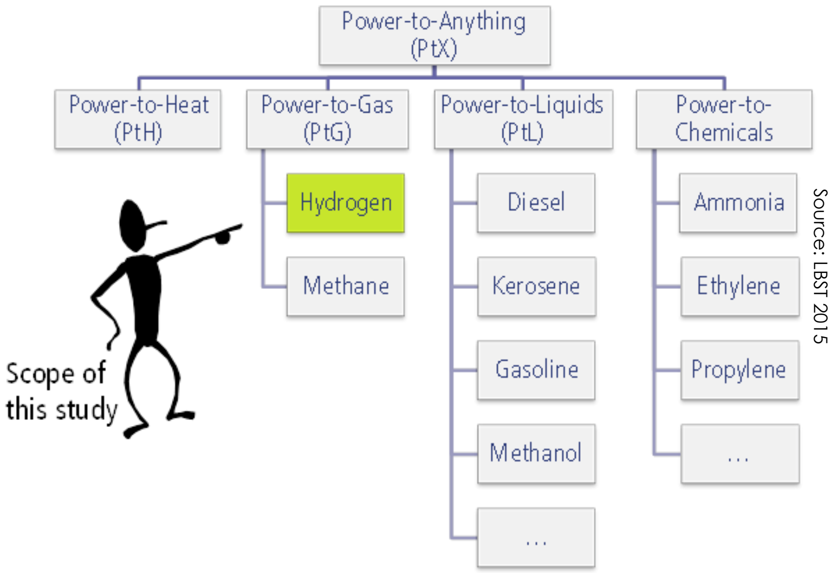


Figure 2: Power-to-X taxonomy

Except for power-to-Heat, all the conversions indicated in Figure 2 initially require the conversion of power into hydrogen via water-electrolysis.

This study focuses on the conversion of electrical power-to-hydrogen for subsequent use as such in various applications, as indicated in Figure 3 showing the integration of a power-to-gas system in the energy system.

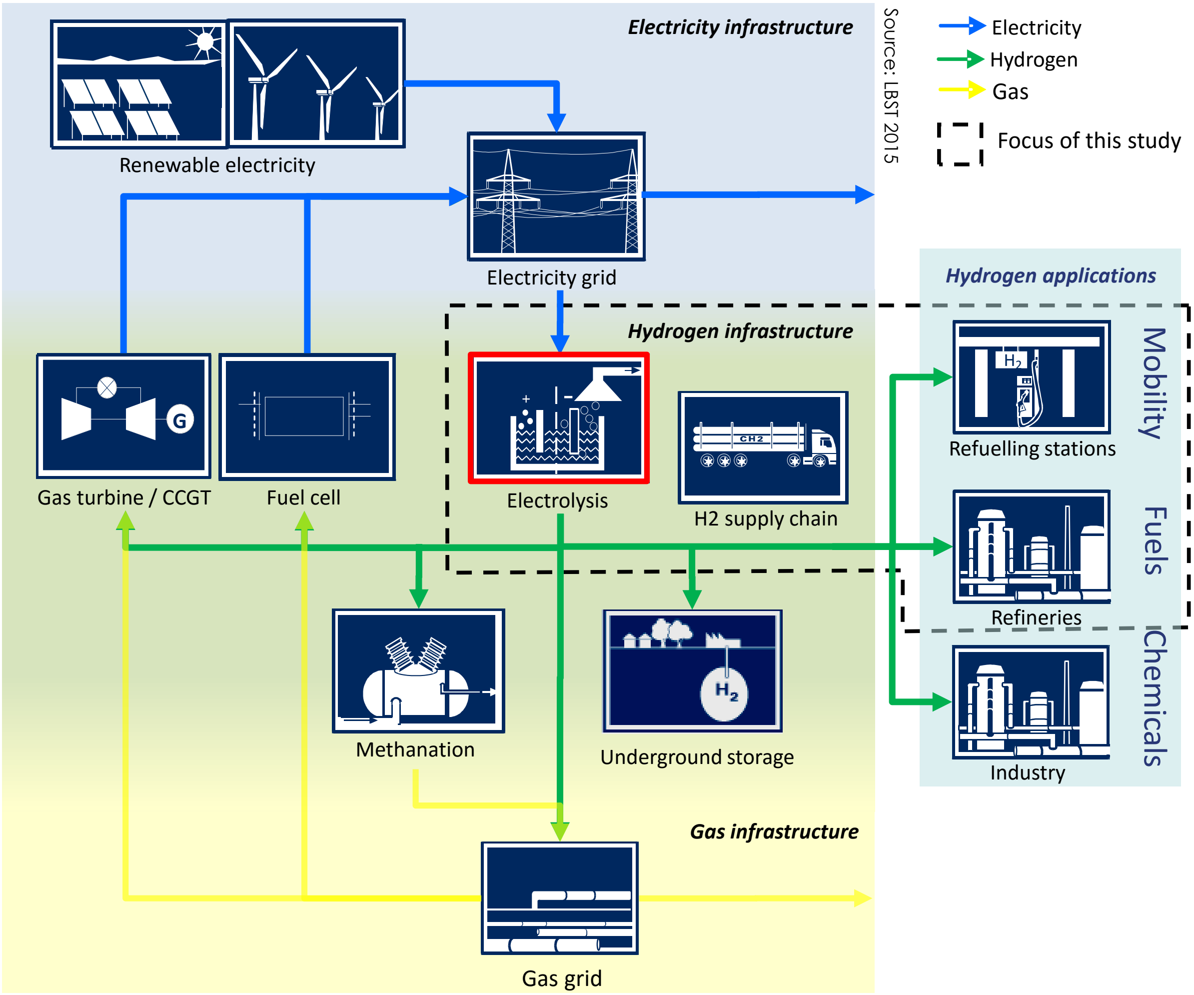


Figure 3: Overview on power-to-gas technologies and applications (source: LBST)

In a first step, we will briefly describe the technologies required for a power-to-gas application including a view on their maturity, typical cost, and any noteworthy boundary conditions. Key technologies include: electrolyser plant, hydrogen conditioning, hydrogen storage, and hydrogen transport and distribution. We will also cover methanation, but will mainly focus on the production and use of hydrogen within this project.

Along with the above technology characterisations, we will also address current challenges and the expected developments within the coming decade.

In a second step, we will give an overview on the most relevant applications for power-to-gas including the production of fuels for mobility, feedstock for refineries and industry, injecting the gas into the grid, and using power-to-gas for long-term electricity storage and grid balancing.

For each of these applications, we will briefly outline the underlying concept, operational modes and requirements, and the main elements of the value chains involved. We will also highlight key issues in current discussions around the applications, including environmental aspects where relevant, and give examples for relevant pilot projects, aiming to provide tangible examples of technology implementations.

The application overview will motivate why we have chosen to analyse the following two applications in more detail: A) using green hydrogen derived from power-to-gas in refineries producing transport fuels, and B) power-to-gas as a means to couple the electricity sector with the mobility and industry sectors.

2.1 Power-to-gas in the energy landscape

2.1.1 Renewables on the rise

According to the IEA's 450 ppm scenario, achieving a global temperature increase of no more than 2° Celsius is conditional upon several objectives, two of which are particularly relevant to this study:

1. Increasing the share of renewable energy production beyond the levels currently set within national climate mitigation plans defined in the Intended Nationally Determined Contributions (INDCs).

Figure 4 illustrates the additional greenhouse gas (GHG) emissions reductions that are needed to that end (IEA *450 Scenario*[4]) in the power generation sector compared to the reductions provided by the INDCs

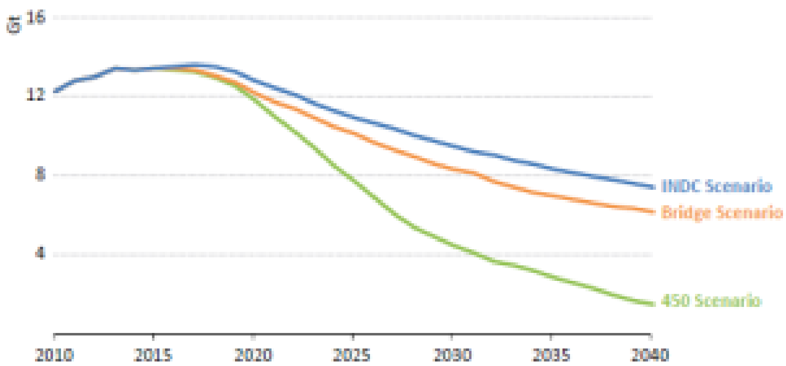


Figure 4: IEA scenarios for GHG emissions reduction in the power sector – [IEA 2015]

Moving from the INDC pathway to the 450 ppm scenario requires an increase in renewable electricity generation investments from B$270/yr in 2014 to B$400/yr in 2025. Indeed, the 450 ppm scenario implies installed capacity grows from 450 GW today to 3300 GW in 2040. As a result, variable renewables increase from 3% of generation to more than 20% by 2040.

[4] Limiting the temperature increase to 2°C requires the atmospheric CO2 concentration to be limited to 450 ppm.

2. Electrification of transport

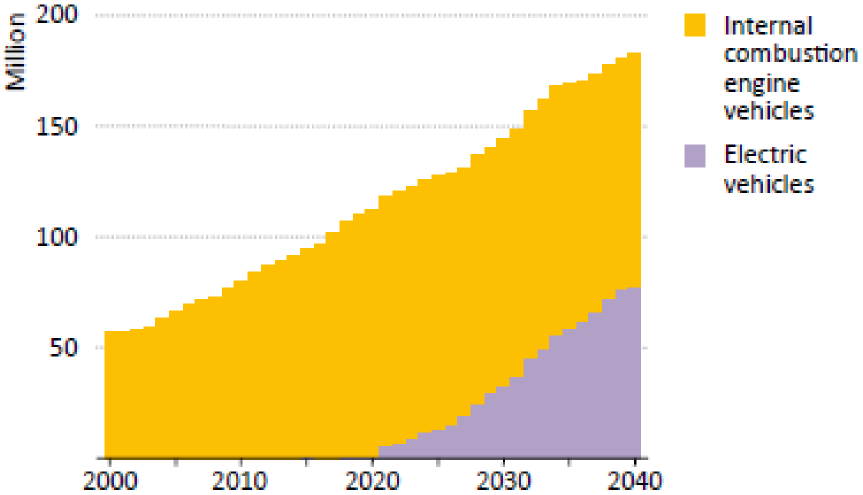


Figure 5: Global light duty vehicles sales by type in the 450 scenario [IEA 2015]

In the 450 Scenario, sales of electric vehicles (EV) cover more than 40% of total passenger car worldwide sales in 2040, almost matching current total passenger car sales.

While this shift in drive-train technology contributes modestly to carbon emissions decrease before 2040, it creates the conditions for achieving the needed reductions beyond 2040.

As the amount of biomass that can sustainably be made available for the production of biofuels is limited, moving away from fossil fuels for the decarbonisation of transport will require resorting to electricity as a secondary energy source. Fuelling transport with electricity will require additional low carbon power generation, in an amount which will strongly depend on the powertrain technologies mix.

According to [IEA 2015], assuming the prevalence of battery and fuel cell electric drive trains for passenger vehicles (requiring significantly less electricity than internal combustion engine vehicles powered by electricity-based synthetic fuels), decarbonisation of transport entails an additional electricity consumption in EU-28 of approximately 2,000 TWh beyond the current consumption levels for stationary applications of 2,800 TWh.

2.1.2 Power-to-gas constitutes a cost-effective source of flexibility that can benefit the energy system as a whole and help improve power generation economics

As illustrated by Figure 6, the substantial variable renewables power production increase negatively impacts the operating conditions of the dispatchable power generation capacity that is needed to maintain grid balance, putting at risk its economic viability, as a result of:

- sharp variations of residual load,
- periods of operation at very low load, potentially requiring curtailment of renewable electricity
- degraded load factors.

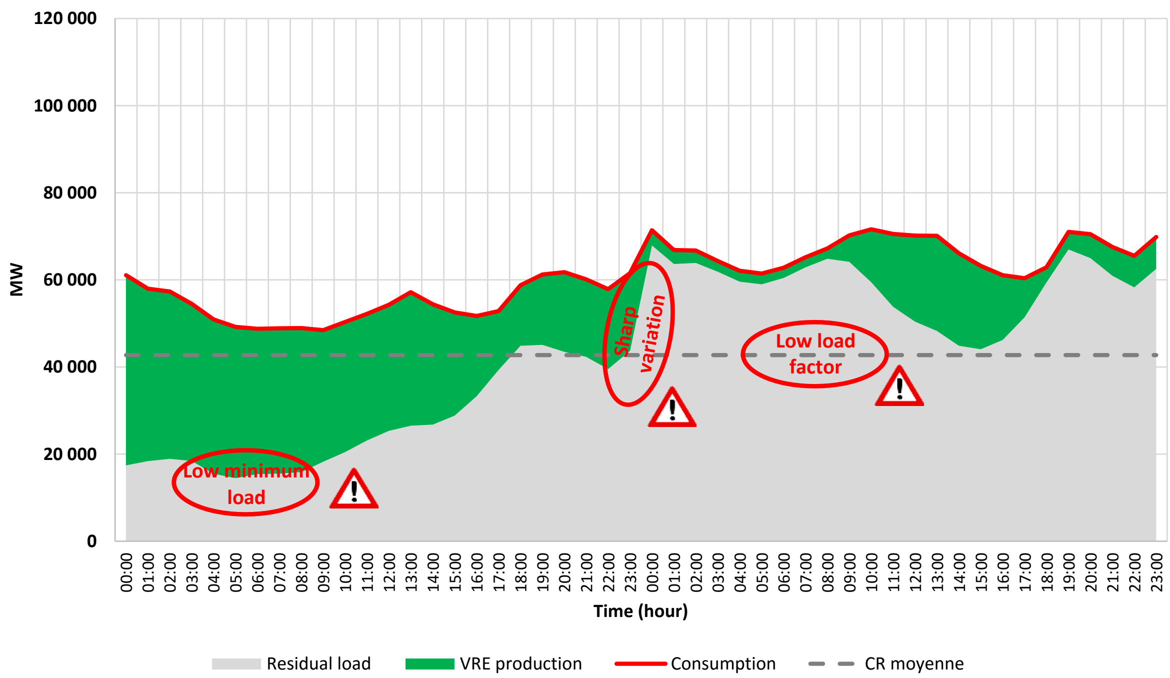


Figure 6: **Power consumption during two days in France in Jan and Feb 2013. Actual VRE[5] production on these days multiplied by 10 (source: Hinicio based on data from RTE)**

In this context, capacity remuneration mechanisms are being discussed as a means to ensure the availability of the dispatchable generation capacity that is needed to ensure the security of supply (power generation adequacy).

Consider now a further addition of variable renewable capacity in order to supply 50% of the electricity needs of transport through power-to-gas consuming 20 GW on average (i.e. electricity consumption increased by 1/3), potentially exacerbating the systemic issues listed above.

However, the power-to-gas system can be operated in a way that strongly alleviates most of these issues suffered in the pre-existing system: (i) residual load is smoothened as the needed flexibility is mainly provided by demand response of the power-to- gas systems and (ii) the load factor of dispatchable power is improved, supplying 50% of the added electricity consumption.

This is illustrated by Figure 7, showing consumption and energy production profiles for the studied configuration.

[5] VRE: variable renewable energy

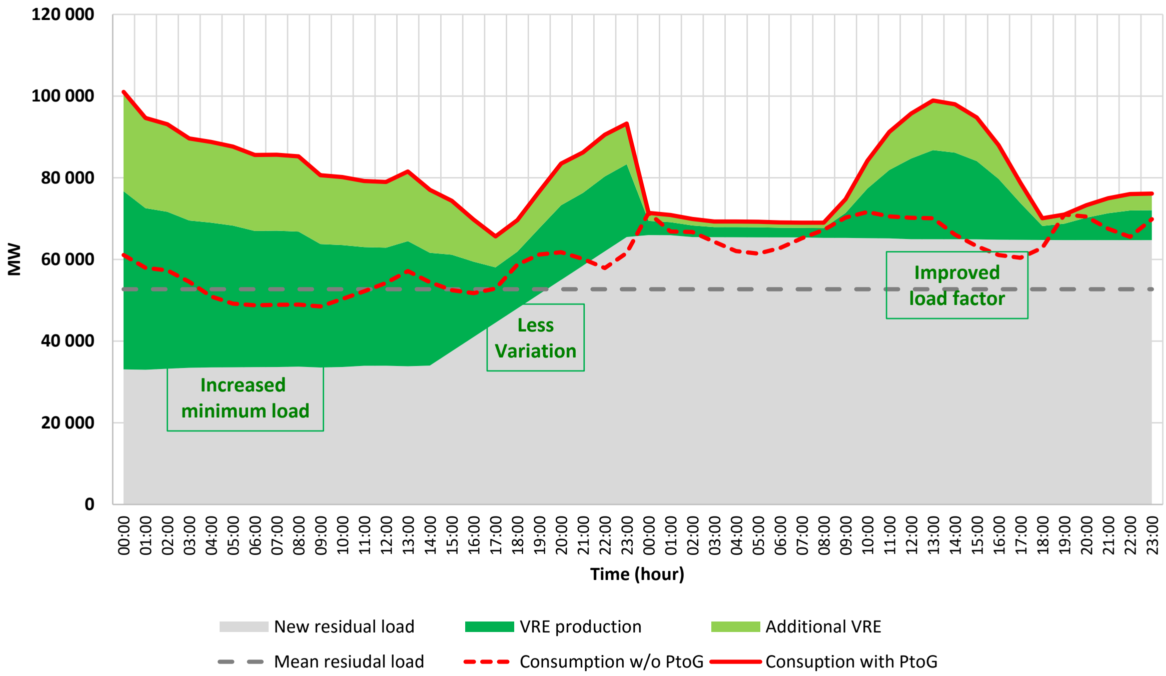


Figure 7: Illustration of the potential impact of power-to-gas on compensating the effects of intermittent power production on a 24-hour period (source: Hinicio)

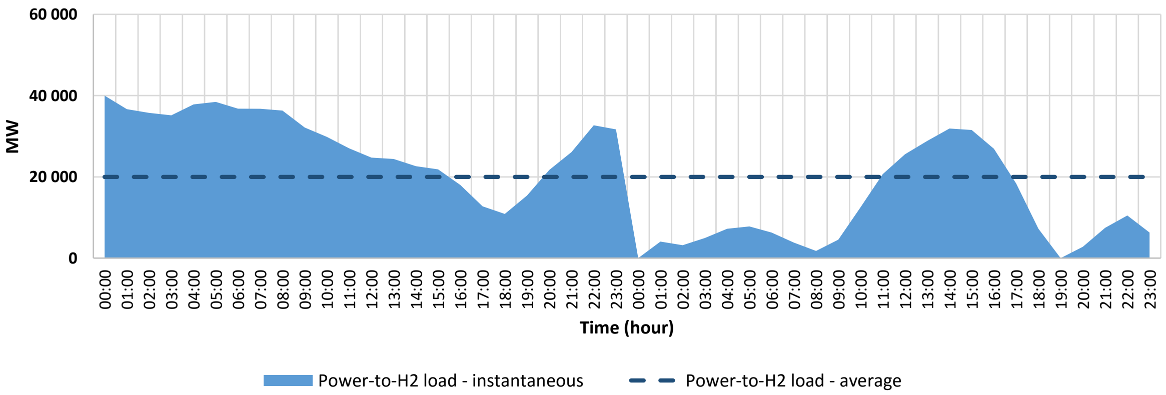


Figure 8: Corresponding power consumed by the electrolyser to mitigate variable renewable power production on a 24-hour period (source: Hinicio)

Starting from the situation shown in Figure 7, the implementation of power-to-gas results in an additional consumption of 20 GW, on average. Half of this is provided by additional VRE. The other half is provided by the existing dispatchable capacity. Power-to-gas load is adjusted to minimise fluctuations of residual load.

Thanks to the buffering capability provided by the gas supply chain, Power-to-gas provides flexibility which is not constrained by energy end-use. Consequently, Power-to-gas can help strongly reduce contingency of the load of dispatchable generation on the fluctuating climatic conditions.

Furthermore, the ability provided by power-to-gas to maintain production also helps avoid curtailment of variable renewable energy production.

In 2014, in Germany, the volume of electricity (1.58 TWh) which had to be curtailed almost tripled compared to the preceding year (0.55 TWh), and amounted to 1.16 % of the renewable electricity production remunerated under the German Renewable Energy Law (EEG, including direct marketing). As in previous years, wind power accounted for 77.3 % of curtailed electricity and was thus, again, the renewable power generation most affected in Germany. The number of PV installations affected has also risen compared to the previous year (11.8 %) and now accounts for 15.5 % of unused energy. 96 % of the curtailed electricity is located in the wind-rich northern federal states, in particular Schleswig-Holstein.

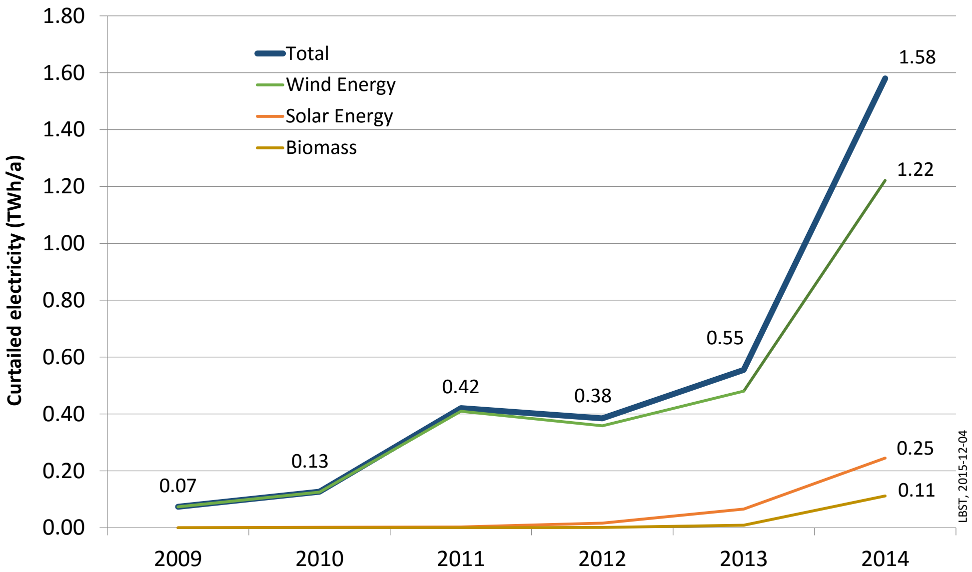


Figure 9: Curtailed renewable electricity volumes in Germany (LBST based on [BNetzA 2015] data)

One of the main reasons why a Power-to-gas system is well suited for providing flexibility in comparison to power generation plants is that the cost of operating a power-to-gas system at partial load (rather than full load, as reflected by the total unit cost of the hydrogen generated) is fundamentally reduced by the fact that operating only when electricity is abundant lowers the unit cost of the electricity consumed.

Indeed, as shown in Figure 10, the unit cost of the hydrogen produced can in this case remain relatively unaffected by operation at partial load. This cost profile can help provide flexibility at an intrinsically lower cost than that delivered by systems operating at constant marginal cost, for which a reduction of load entails an increase of product unit cost.

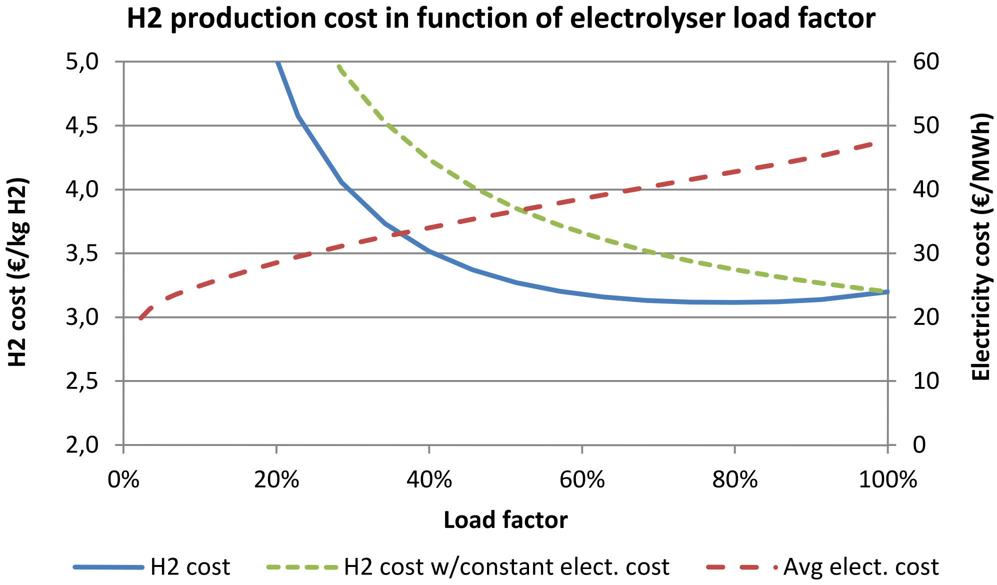


Figure 10: Total cost of hydrogen produced by a power-to-hydrogen system[6] (source: Hinicio)

Due to the decrease of the average cost of electricity as the load factor decreases (red curve), the total cost per kg of hydrogen (blue curve) is relatively constant down to a load factor of 50%, in contrast to the case where the electricity cost does not decrease with load (green curve).

In conclusion, conversion of power-to-hydrogen can not only support the decarbonisation of transport via the implementation of decarbonised fuels (gaseous or liquid), but also constitutes a cost effective source of flexibility benefiting the power system as a whole and providing improved economics for power generation, thanks to:

- improved load factors of dispatchable capacity and less curtailment of variable renewable capacity;
- more predictable and smoother operation of dispatchable capacity.

The improved visibility on load could facilitate investment in the dispatchable generation capacity that is needed to ensure power generation adequacy, minimizing the need for capacity remuneration mechanisms.

[6] assuming an installed electrolyser cost of 0.55 M€/MW at 2030 horizon, and the electricity price duration data for France in 2014, including grid charges

2.1.3 Power-to-gas can also help address balancing needs at short time scales

Flexibility resources are increasingly required at short timescale to compensate the difference between forecasted and actual VRE production. This need is exacerbated by the fact that the relative share in total production of the conventional power plants that were until now providing the needed reserve capacity is decreasing.

Consequently, there is significant value to be tapped by being able to provide positive or negative adjustment at very short notice. A flexible capacity can currently double its revenues by going on the intraday (quarter hour) market, due to the high price volatility [Lantrain 2015].

Water electrolysis, the technology at the centre of Power-to-gas converting electrical energy into hydrogen, is very well suited for providing flexibility at short time scales.

While electrolysis has been implemented industrially for almost a century for the production of hydrogen as a chemical, recent developments have focussed on exploiting the technology's potential with regards to energy efficiency and dynamic response. The table below provides indications on the performance of the incumbent Alkaline technology using a liquid electrolyte, and on the more recently developed PEM technology using a solid electrolyte.

PEM technology has intrinsic advantages over Alkaline with regards to current density, dynamic response, and operation at elevated pressure. The latter feature reduces the amount of compression required downstream for storage and distribution.

Furthermore, the possibility for a PEM stack to operate at much higher current densities than the nominal value (which provides the targeted energy efficiency) allows the stack to be operates momentarily at a peak load which may be as high as 200% of nominal load. This is a key advantage for offering primary frequency control services requiring load to be instantaneously turned up or down from the point of normal operation.

With regards to cost, PEM technology offers very significant cost reduction potential as it is at the beginning of its development curve. An additional factor is that manufacturing of the electrolyser stack can be addressed by planar technologies, a configuration that is favourable for cost reduction as observed for other devices where planar manufacturing technologies are applied, such as PV solar panels.

Table 1: Characteristics of PEM and Alkaline electrolysers (source: Hinicio)

	Alkaline	**PEM**
Development stage	Industrial since 1920s	Early stage commercialization
Maximum capacity	Unit: 3.8 MW/67,7 kg/h Plant: 100 MW/1900 kg/h (Zimbabwe)	6 MW/ 120 kg/h (3 x 2 MW pilot unit)
Current density	Up to 0.4 A/cm^2	Up to 2 A/cm^2 (R&D: 3.2 A cm^{-2} at 1.8 V at 90°C)[7]
Dynamic response	Less than one minute	Within seconds
Peak load	100%	200% (30 min)
Turn down	20 – 40 %	<10 %
Operating pressure (typical)	A few bars	Tens of bars
Investment costs (incl. installation)	1.1 M€/MW [Stolzenberg 2013]	1.9 M€/MW [FCH JU 2014]
Operating cost	5 - 7 %	4 %

In conclusion, through the combination of high flexibility and large storage capacity, Power-to-Gas can support balancing at any time scale, from supply of primary reserve to seasonal storage (with underground storage.) The capability to provide such a wide range of services further contributes to this function's cost effectiveness.

2.1.4 Power-to-gas can support the integration of renewables at any point in the T&D system

As electrolysis technology is highly scalable, power-to-gas can be applied at the scale that is the most appropriate for addressing particular needs of the hydrogen application, e.g. fuelling transport in a given area, or the grid balancing needs, e.g. restoring balance between local electricity consumption and local production following the addition of VRE generation capacity, reducing the need for grid expansion.

The latter situation can be expected to be increasingly common as renewable power capacities are mainly connected to the distribution grid (see Figure 11), which is where generation capacity addition has the greatest likelihood of resulting in situations where local production exceeds local consumption.

[7] Results of FCH JU funded ElectroHyPem project

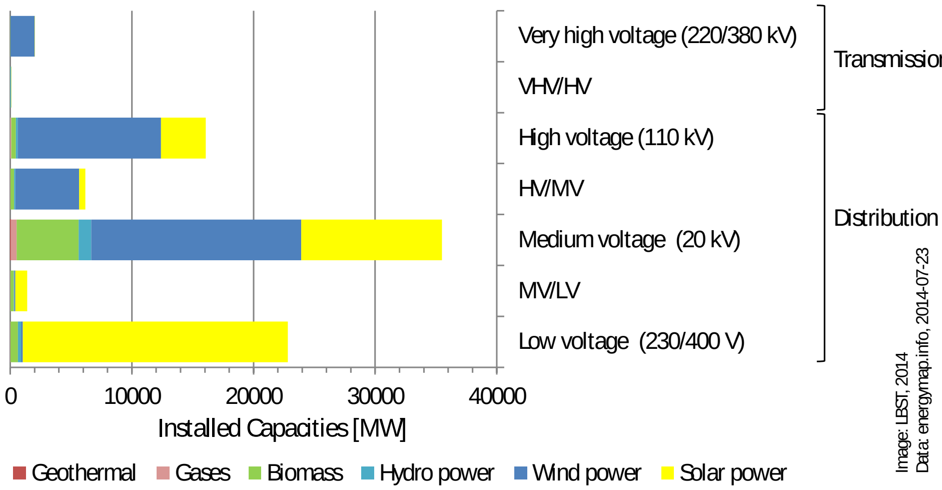


Figure 11: Renewable power capacities connected to the grid in Germany as per July 2014 (source: LBST based on data from energymap.info)

Power-to-gas provides a unique way of achieving balance when average local production exceeds local average consumption. Indeed, in this case, other flexibility options such as reversible storage or demand response, which only provide time-shift, will not allow to restore balance between production and consumption.

Figure 12 illustrates the increasing scale at which power-to-gas projects have been implemented in the past years, with a relatively balanced deployment of PEM and alkaline technology in the recent years.

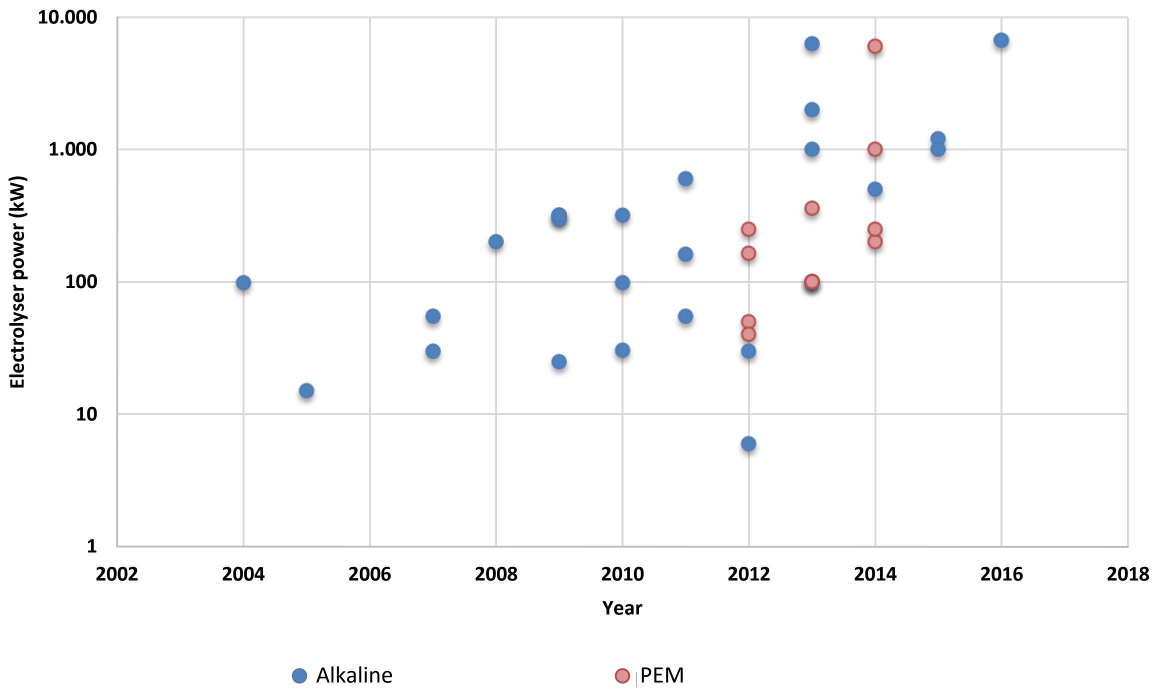


Figure 12: Installed capacity of power-to-gas pilot plants – (source: Hinicio from [Gahleitner 2013])

Figure 13 illustrates the implementation of power-to-hydrogen systems, including the hydrogen distribution infrastructure, at different size scales.

In the "on-site" case, the power-to-hydrogen system is dedicated to the production of hydrogen for a given application on the same location, eliminating the need to transport the hydrogen.

In the "centralised" case, power-to-hydrogen addressing the needs of hydrogen over a relatively large geographic area for a relatively large number of points of use, implying hydrogen transportation over distances which may reach hundreds of km. While this entails relatively high transportation costs (transportation over 300 km adds a cost that is roughly equal to the total costs of production and conditioning), the centralised configuration not only provides economies of scale, but also facilitates the provision of grid-services and the selection of an optimal location with regards to interfacing with the electrical and natural gas grids. It is to be noted that hydrogen is currently typically delivered over such large distances from a limited number of trailer filling facilities in each country.

The semi-centralised case, where the power-to-hydrogen system addresses needs in a radius not exceeding 50 km, limits the cost of transportation, but still provides economies of scale and the possibility of choosing an optimal location for the system to interface with the electricity and gas infrastructure. With the development of hydrogen mobility, such a coverage could be optimal, as a 1 MW system allows to fuel a fleet of about 100 fuel cell electric vehicles[8].

In the case hydrogen is not used as such, the function of the power-to-gas system is only to allow transfer of energy from the electric grid to the natural gas grid. While this can very effectively support grid balancing, creating the conditions of an economically balanced business case is more challenging, mainly due to the fact that the market value of the input (electricity) is higher on average than that of the output (gas in the natural gas grid).

[8] Consuming each 1 kg H_2/100 km and driving 15 000 km/yr, assuming an electrolyser energy consumption of 50 kWh/kg H2.

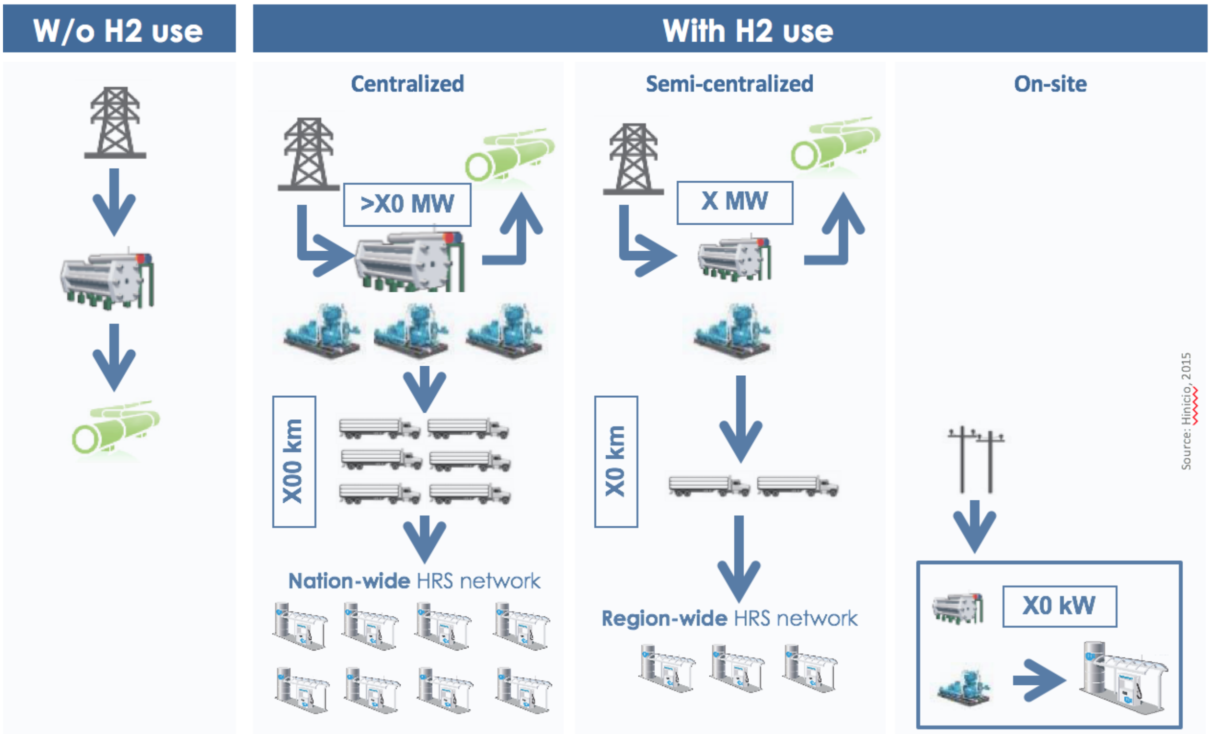


Figure 13: Illustration of various power-to-hydrogen configurations (source: Hinicio)

2.1.5 Hydrogen injection into the natural gas grid enhances a power-to-Gas system's ability to provide grid services

While there is less value to be tapped from injecting hydrogen into the natural gas grid than providing hydrogen to the market, this outlet has the advantage of allowing electrolysis operation to be steered by the provision of balancing services to the grid, even if the electrolyser's production capacity exceeds local market demand for hydrogen, providing additional value.

Direct injection is the most cost effective way to "dump" hydrogen from excess RE into the gas grid. In this case, hydrogen is blended with natural gas in controlled conditions to ensure that the natural gas meets the required specifications, especially in terms of heating value, density, and Wobbe index[9].

Depending on the origin of the natural gas, generic natural gas specifications can be met despite hydrogen contents of up to 15% in volume [DVGW 2011].

However, some gas users have stricter constraints. This is the case for instance for power plants, where gas turbines are calibrated for a specific heating value, as well as natural gas vehicles, for which the hydrogen content is limited to the maximum value considered for the homologation of the on-board CNG fuel tank, which may be as low as 2 vol-% according to UNECE R110.

[9] The Wobbe index is used to compare the combustion energy output of different composition fuel gases in an appliance (fire, cooker etc.). If two fuels have identical Wobbe Indices then for given pressure and valve settings the energy output will also be identical.- source Wikipedia

Also stricter limits may be specified for particular natural gas infrastructure sub-systems, such as compression stations on the transmission grid, or underground storage facilities.

Therefore, the concentration limits applicable for direct injection of hydrogen into the natural gas network today need to be determined on a case-by-case basis.

Conversion of hydrogen into synthetic methane prior to injection by combination with CO2, as step called methanation, eliminates the limit on blending concentration, as methane can be mixed in any proportion with natural gas without impact on downstream applications.

This step requires a concentrated CO2 source and introduces additional equipment costs and energy losses, with a negative impact on the economic justification of injection of gas derived from electricity into the gas grid. On the up-side, there are potential synergies with the CO2 generating process to be exploited, as the methanation process is exothermal.

2.2 Regulatory framework

2.2.1 Policy targets

The implementation of power-to-hydrogen can help address a variety of climate related objectives:

- Reduction of greenhouse gas emissions in transport thanks to the use of low carbon primary energies, either through reduction of the carbon content of liquid fuels by use of power based (rather than fossil energy based) feed-stock for the production of these fuels, or through the implementation of new low carbon energy carriers such as electricity, hydrogen or electricity-based methane, which typically requires also a change of drive train technology and distribution infrastructure
- Increase of the share of renewable energies, by facilitating the integration of variable renewables without compromising power system reliability
- Reduce energy consumption by supporting the shift to electric powertrains in ground transport which are more energy efficient than internal combustion based powertrains

Power-to-gas is consequently supported by various European and associated national energy policy targets, presented in Table 2, including those laid out by the Fuel Quality Directive and the Renewable Energy Directive.

The Fuel Quality Directive is presented in further detail in the following section.

Table 2: Environmental policy targets in France, Germany and international (amended from [MFS 2015])

Topic	Sector	World	EU	France	Germany
Greenhouse gases	All sectors	< 2°C (COP21)	2020: $-20\%_{1990}$ 2030: $-40\%_{1990}$ 2030*: $-30\%_{1990}$ 2040: $-60\%_{1990}$ 2050: $-80/-95\%_{1990}$	2030: $-40\%_{1990}$ 2050: $-75\%_{1990}$	2020: $-40\%_{1990}$ 2030: $-55\%_{1990}$ 2040: $-70\%_{1990}$ 2050: $-80/-95\%_{1990}$
	Transport		2020: $-6\%_{2010}$ (FQD) 2050: $-60\%_{2010}$ (COM 2011 144)	2020: $-10\%_{2010}$ 2028: $-22\%_{2013}$ 2050: $-70\%_{2013}$	2015: $-3.5\%_{2010}$ 2017: $-4\%_{2010}$ 2020: $-6\%_{2010}$ (BImSchG)
Renewable energy	All sectors		2020: 20% 2030: 27%	2020: 23% 2030: 32%	2020: 18% 2030: 30% 2040: 45% 2050: 60%
	Electricity				2020: 35% 2030: 50% 2040: 65% 2050: 80% (EEG 2012)
	Transport		2020: 10% (RED)	2020: 10% 2030: 15%	
Energy consumption	All sectors		2020: $-20\%_{1990}$ (COM 2011 112) 2030: $-27\%_{1990}$	2030: $-20\%_{2012}$ 2050: $-50\%_{2012}$	2020: $-20\%_{2008}$ 2030: / 2040: / 2050: $-50\%_{2008}$
	Transport			2030: $-30\%_{2012}$ fossil energy	2020: $-10\%_{2008}$ 2030: / 2040: / 2050: $-40\%_{2008}$
SOURCES			[EC-144 2011] [EC-112 2011]	[loi 2011-12] [loi 2015-992] [Code de l'énergie]	[Energiekonzept 2010]

* 2030 without EU-ETS

2.2.2 EU

Fuel Quality Directive (FQD)

Article 7a 2.a of the Fuel Quality Directive (FQD, 2009/30/EG) defines the following greenhouse gas (GHG) emission reduction targets for the supply of energy for road vehicles, non-road mobile machinery, including inland waterway vessels, agricultural or forestry tractors as well as recreational craft:

- 2 % by 2015
- 4 % by 2017
- 6 % by 2020

By 2020, a 10 % GHG emission reduction has to be achieved compared to a 2010 fossil fuel baseline standard of 94.1 g $CO_{2equiv.}$/MJ which is defined in Annex II (2015/652/EU). However, only 6 % GHG emission reductions are mandatory. The remaining 4 % GHG emission reduction is mentioned in the FQD preface only. Their fulfillment is thus not binding for EU Member States. The 4 % may be achieved by purchasing credits under the Clean Development Mechanism (CDM) of the Kyoto Protocol (2 %) and by using carbon capture and storage (CCS) technology as well as electric vehicles (2 %).

Each Member State shall designate the supplier or the suppliers responsible for monitoring and reporting the life-cycle GHG emissions of its supplied fuels (Article 7a 2.). The FQD allows pooling, i.e. that a group of suppliers may team up to jointly meet the reduction obligation (Article 7a 4.).

The emission reduction targets can, in principle, be met with any technology capable of reducing GHG emission. Hereto, the preface (9) explicitly mentions the use of biofuels, alternative fuels as well as reductions in flaring and venting at production sites. For alternative fuels to count towards this policy target, compliance with certain sustainability criteria as depicted in the FQD Annexes must be given and certified. For certain fossil fuels Upstream Emission Reductions (UERs) can also be used to fulfill the reduction obligation (ANNEX I, 2015/652/EU).

FQD sustainability criteria for power-to-hydrogen are still to be implemented. The EU project *CertifHy*[10] is developing criteria for "sustainable" and "low carbon" guarantees of origin (GoO) for hydrogen. The GoO concept may serve as a basis for EU sustainability criteria for renewable hydrogen.

The GHG intensity of hydrogen fuel from electrolysis fully powered by non-biological renewable energy for the use in a hydrogen fuel cell is 4 g CO_{2equiv}/MJ. It is calculated based on a life cycle GHG intensity of gaseous hydrogen (9.1 g CO_{2equiv}/MJ) multiplied by the so-called adjustment factor (AF) for powertrain efficiencies (0.4 for hydrogen fuel cell electric powertrains). The GHG intensity for other hydrogen sources is listed in Table 3.

[10] http://www.certifhy.eu

Table 3: Greenhouse gas intensities of hydrogen from various sources for use in fuel cell electric vehicles based on FQD ANNEX I (2015/652/EU)

Hydrogen source	EU default GHG value well-to-tank (g $CO_{2equiv.}$/MJ)	Adjustment factor (AF) for fuel cell electric vehicles (ICE ≡ 1)	Resulting GHG intensity relevant for obligation fulfilment (g $CO_{2equiv.}$/MJ)
Natural gas	104.3	0.4	41.7
Coal	234.4	0.4	93.8
Coal with CCS	52.7	0.4	21.1

The FQD as per 2009 does not stipulate any consequences in case of non-compliance. However, the new Council Directive (2015/652/EU) laying down methods and reporting requirements pursuant to the FQD mentions penalties in case of non-compliance. Article 6 requires Member States to lay down rules on penalties that are effective, proportionate and dissuasive.

The FQD sets targets up to 2020. There is an ongoing wider EU debate on post-2020 targets. So far, the future of the FQD is open. In order to maintain investment certainty, the bioenergy industry is pleading to continue the FQD beyond 2020 with minimum targets not below 2020 levels.

Renewables Energy Directive (RED)

- 2009/28/EC, amended with 2015/652/EU
- 2020: 10 % of renewable energy in transport
- Use sustainable biofuels involving significant GHG reduction in comparison with fossil fuels (35% nowadays to 60% in 2018)

2.2.3 Germany – National implementation of RED and FQD

On the national level, the FQD is implemented in the "Bundes-Immissionsschutzgesetz – BimSchG" (Federal Immission Protection Law). Greenhouse gas emission reduction targets for 2020 and intermediate targets for 2015 and 2017 are defined in §37a (BImSchG). Fulfilment is mandatory for fuel suppliers in Germany.

Until 2014 (including), suppliers were obliged to achieve certain biofuel shares for target fulfilment (energy target) which were as following:

- 4.4 % (energy) biofuel share for diesel
- 2.8 % (energy) biofuel share for petrol

In total, a minimum share of at least 6.25 % of biofuels was mandatory for target fulfilment.

Since 2015, GHG emission reduction targets replace the energy targets, in line with the FQD's emission-based target setting. The legally binding emission reduction targets for suppliers in Germany are now:

- 3.5 % by 2015,
- 4 % by 2017 and

- 6 % 2020.

The achieved emission reduction is calculated by subtracting the real GHG emission of a given year from a reference value. The reference value is calculated by multiplying the energy content of non-renewable petrol and diesel fuels (including biofuels that are sold but do not meet sustainability criteria) with the base value (fossil comparator) of 83.8 kg CO_2-equivalent per Gigajoule (1).

$$(1)\ Reference\ GHG\ emission\ value\ = \sum_{i=1}^{all\ fuels} (energy\ of\ fuel\ (i)) \times 83.8\ \frac{kg_{CO2equiv.}}{GJ}$$

The real GHG emissions are calculated by multiplying the energy content of each individual fuel with a fuel specific emission factor. The fuel specific emission factor is defined in the sustainability certificate of each biofuel. Petrol, diesel and other not eligible fuels are multiplied with the base value of 83.8 kg CO_2-equivalent per Gigajoule. The sum of all fuel GHG emissions equals the real GHG emission (2). The use of company or other fuel specific emission factors is not included in the BImSchG.

$$(2)\ Real\ GHG\ emissions\ value = \sum_{i=1}^{all\ fuels} energy\ of\ fuel\ (i)\ \times\ emission\ factor\ (i)$$

The spread (in kg CO_2-equivalent) between the reference value and the real value equals the achieved GHG emission reduction (3).

$$(3)\ Emission\ reduction\ = Reference\ GHG\ emission\ value - Real\ GHG\ emission\ value$$

Emission reduction and energy tax obligation are bound together. Meaning, the responsible entity for energy tax payments is automatically also the responsible entity for fulfilling the emission reductions. In Germany, the energy tax on fuels is due at the point where the fuel leaves the premises of the customs-approved fuel producer. This is usually the refinery making it the tax debtor and thus the emission reduction responsible entity to this end.

The emission reduction responsible entity can transfer the emission reduction to another entity. However, the obligation to fulfil a certain emission reduction cannot be transferred. Analogue to the EU FQD, the German BImSchG allows for two or more suppliers to create a pool and jointly achieve the required reduction targets.

The reduction targets can be achieved by blending fossil fuels and biofuels (including biomethane) or by the distribution of neat biofuels. Thus, as yet, electricity and other alternative fuels, such as hydrogen, cannot be considered in the calculation of emission reduction (§37a BImSchG) in Germany. The FQD as well as the BImSchG mention renewable electricity and electricity-derived fuels as possibly eligible fuel. However, to date, the required legal ordinance to enact this in Germany has not been passed. §37d (2) of the BImSchG[11] defines the possible scope of the legal ordinance. Here the department being responsible for the ordinance is empowered to extend the methodology of greenhouse gas emission calculation beyond biofuels – (silent) agreement by the German Parliament provided – to possibly also include:

- renewable electricity (point 11),

[11] The legal permissibility for this short-cut procedure is called "Verordnungsermächtigung".

- further renewable fuels (point 12) and
- additional measures for GHG mitigation (point 13).

The legal ordinance could be the vehicle to include renewable hydrogen used in refineries in the list of eligible measures for the fulfilment of the greenhouse gas emission reduction target for fuels.

If the required emission reductions are not achieved, a penalty has to be paid. The penalty amounts to 0.47 €/kg of missed greenhouse gas emission reduction (§37c BImSchG), i.e. 470 €/t CO_2.

2.2.4 France – National implementation of RED and FQD

National implementation of RED and FQD

The Renewable Energy Directive and Fuel Quality Directives were transposed into French law in September 2011 [2011-9]

It is to be noted that whereas the FQD strictly requires a 6% reduction in overall fuel GHG emissions intensity by 2020 (the additional 4% objective being indicative -see section 2.2.2), the reduction required by French regulation is 10%, taking as reference the emissions intensity observed in the EU in 2010.

The more specific requirements relative to the renewable content of fuels (in RED) and the reduction of the GHG emissions intensity of fuels (FQD) referred to, for France, in [2011-11] are largely similar to those prescribed in the RED and FQD.

These requirements have since been integrated into the Code de l'Energie, a structured compilation of the regulatory requirements applicable in the area of energy. GHG emissions intensity reduction is covered by articles L641-7, L641-8 and R641-12

The 10% GHG emissions intensity reduction requirement is broken down as follows:

- 6% reduction of the life cycle emissions of gasoline, diesel, and E85;
- 2% (indicative) through the use of electrical energy in any type of vehicle (including off-road and non-land) or the use of any technology, including CCS, reducing GHG emissions over the life cycle of the fuel or the energy used in the vehicle;
- 2%(indicative) through the purchase of carbon credits.

Using hydrogen produced from low carbon electricity in refineries would contribute to the 6% reduction of the life cycle emissions of gasoline diesel and E85. Therefore, in the short term, providing green hydrogen to refineries would allow them to contribute to this objective.

Article L641-8 of Code de l'Energie refers to the preparation of a ministerial decree specifying the content of the annual report to be provided by fuel producers, the methods to be applied for calculating the GHG emissions over the whole lifecycle of the fuel, and the means of controlling the aforementioned calculation, however this decree has not yet been published.

It is to be noted that the implementing directive laying down at EU level calculation methods and reporting requirements pursuant to the FQD (EU 2015/652) was only enacted in April 2015, and that the member states have until 2017 to transpose it into their regulation.

Loi de Transition Energétique (LTE)

The Loi de Transition Energétique pour la Croissance Verte [LTE 2015], which was voted through in 2015, aims to provide France with the means to fight against climate change, to preserve the environment and to reinforce its energy security whilst maintaining competitive energy prices and guaranteeing energy access to all. To this aim, the LTE sets legally binding strategic objectives at the 2050 horizon for GHG emissions' reduction, reducing final energy consumption, reducing fossil primary energy, increasing the share of renewable energy and limiting the share of nuclear power.

The LTE provides new policy tools, such as the low carbon strategy (SNBC) which sets maximum emission levels for transport, energy production, agriculture and the construction sector over the next fifteen years divided into three 5-year carbon budgets. The SNBC will be regularly updated to guarantee that the 2020 and 2030 climate and energy objectives are met. Furthermore, the multiannual planning procedure in the area of energy (which sets out government investment policy in the energy sector) was modified to further its impact by bringing together electricity, gas and heat under a single umbrella with five-year revision cycles. The main economic instrument supporting the LTE is a new carbon tax for which prices have been set at 56 €/t in 2020 and 100 €/t in 2030.

The LTE emphasises the importance of developing clean transport to improve air quality and achieve healthier living conditions. The fulfilment of this ambition is based on the development of less polluting modes of transport, improving energy efficiency, encouraging the deployment of renewable energies, reducing GHG emissions and atmospheric pollution as well as measures aimed at improving air quality.

The means to tackle these issues in the transport sector include a series of compulsory measures. By 2025, the national and local public administration light vehicles, light commercial and heavy vehicles' fleet must be composed of at least 50% low carbon emission vehicles. By 2020, 50% of newly procured vehicles in public transport companies with a fleet of more than 20 busses must be low emissions. At the same time horizon, 10 % of all new vehicles purchases by taxi and car rental companies operating a fleet of ten cars or more must be "low consumption" vehicles. Further indicative incentives are proposed such as the creation of designated parking spots, discounted motorway tariffs and lanes dedicated to low carbon vehicles. Cities are given the possibility of restricting downtown access on the basis of vehicle emissions. All the articles pertaining to transport within the LTE are technology neutral. Therefore, the application decrees ought to apply to hydrogen.

Article 121 refers specifically to hydrogen use for energy storage. The LTE states that, within 12 months from the date of implementation, the government will submit to parliament a strategy for the development of decarbonised hydrogen storage for renewable energy which will specifically present:

1) The implementation of a business case for renewable electricity storage using hydrogen, aiming to encourage renewable energy producers to contribute to the availability and the implementation of the reserves required for reliable operation of the public transport and distribution networks, as well as conditions of remuneration of these services
2) Incentive measures aimed at promoting technological innovation, notably for fuel cells, for the electric vehicle market
3) The deployment of a network of hydrogen refuelling stations
4) The changes of regulation required for allowing the deployment of these new hydrogen applications, such as power-to-gas.

2.3 Power system

The key aspects of the French and German power system impacting economic balance of a Power-to-gas system are described hereafter.

2.3.1 Cost structure of electricity

France

In France, like in many countries, the price of electricity to the end-user is composed of three parts: the cost of electricity production (including management and marketing costs), the cost of electricity transportation and taxes.

In France, for many end users, the price per kWh (or tariff) of electricity is regulated, set upon government decision, as is the price of electricity transport. The level of these power consumption tariffs are set so as to ensure that the price of electricity covers the costs of the electricity system. For example, the grid fee tariff at level which covers the actual transport costs and reimburses the grid operators' investment costs. The Commission de Régulation de l'Energie (CRE) calculates these costs. Annually, the CRE provides the government with recommendations as to the rate to set. Thereafter, the government modifies these rates.

Whereas, before 2016, all users could benefit from a government-set per kilowatt hour price of electricity, today, consumers with power subscriptions below 36 kVA may choose whether they wish to purchase electricity at the regulated tariff (provided by EDF) or at a different price set by market conditions (via an alternative electricity provider). For consumers subscribing to more than 36 kVA, the price of electricity is set by the market.

The power transport costs are covered by a grid fee: the Tarif d'Utilisation des Réseaux Publics d'Electricité (Tariff for the use of public electricity networks) or TURPE.

The TURPE is based upon 4 guiding principles:

1) The tariff is the same for the entire national territory;
2) The tariff is independent of the distance covered between the point of injection and the point of withdrawal;

3) The tariff depends upon the supply voltage, subscribed power and withdrawn energy;
4) For some versions of the TURPE, the tariff varies depending on the season, day of the week and/or hour of the day.

The third price component are taxes. Until recently, electricity taxes were: the CSPE, the TCFE, the CTA and (for non-professional customers) VAT (for an overview of each tax see Table 4). However, following the promulgation of the LTE, energy fiscal policy is being reformed. A carbon price will be integrated into the tax on the final consumption of energy (TCFE). Also, the CSPE will be integrated to the TCFE. Although the main elements of energy fiscal reform are known, the application decrees which define the detailed modifications and applications have, as yet, not been published. Therefore, the taxes and rates which are being presented are based on best available data, but may not be representative of future conditions.

Table 4: Characteristics of electricity tariffs and taxes in France

Component	Explanation
CSPE (Contribution to the social use of public energy)	The CSPE is a levy which covers the costs of Feed-in-tariffs for renewable energy production, the reduced social tariff for low income individuals, and ensures that the per kWh price of electricity is the same for all individual consumers who live in French territories which are not connected to the main electricity grid. Its per MWh rate is fixed by the French government.
CTA (contribution to the transport tariff)	The CTA finances electric and gas industries employee pensions. The CTA is a lump sum levy which varies depending on the subscribed power, the type of meter… and is additional to the cost of subscription.
TCFE (Tax on the final consumption of electricity)	The TCFE is a tax on power consumption. It is collected by electricity providers and redistributed to the departmental and communal public bodies. Its rate therefore depends on local conditions and is re-evaluated on an annual basis.
TURPE (tariff for the use of electricity networks)	The TURPE covers the network running and investment costs. It is paid by all consumers. Its rate depends largely on the supply voltage, the contracted power capacity and the amount of energy actually consumed. There are several TURPE tariff options some to provide additional services (such as emergency support) or the possibility of subscribing to a tariff which varies depending on the time (season, day, hour in the day) when the consumer uses the network.
VAT	For individual consumers, VAT is reduced to 14% on the price of the subscription, but is at 21% for the electricity consumed. Non-residential consumers are exonerated from VAT.

The majority of consumers are subject to these taxes. However, highly energy intensive companies subject to international competition can benefit from tax reductions and exonerations under the électro-intensif regime. The eligibility conditions for this status and its associated tax and grid tariff exemptions will be presented in section Grid fees and Taxes as they are particularly pertinent for the business case evaluation of Power-to-gas in France.

Germany

The **regulatory framework for electricity** – as part of the energy sector – is very complex. Figure 13 gives a schematic overview over acts and ordinances that have been put in place over time to implement the energy concept of the German federal government.

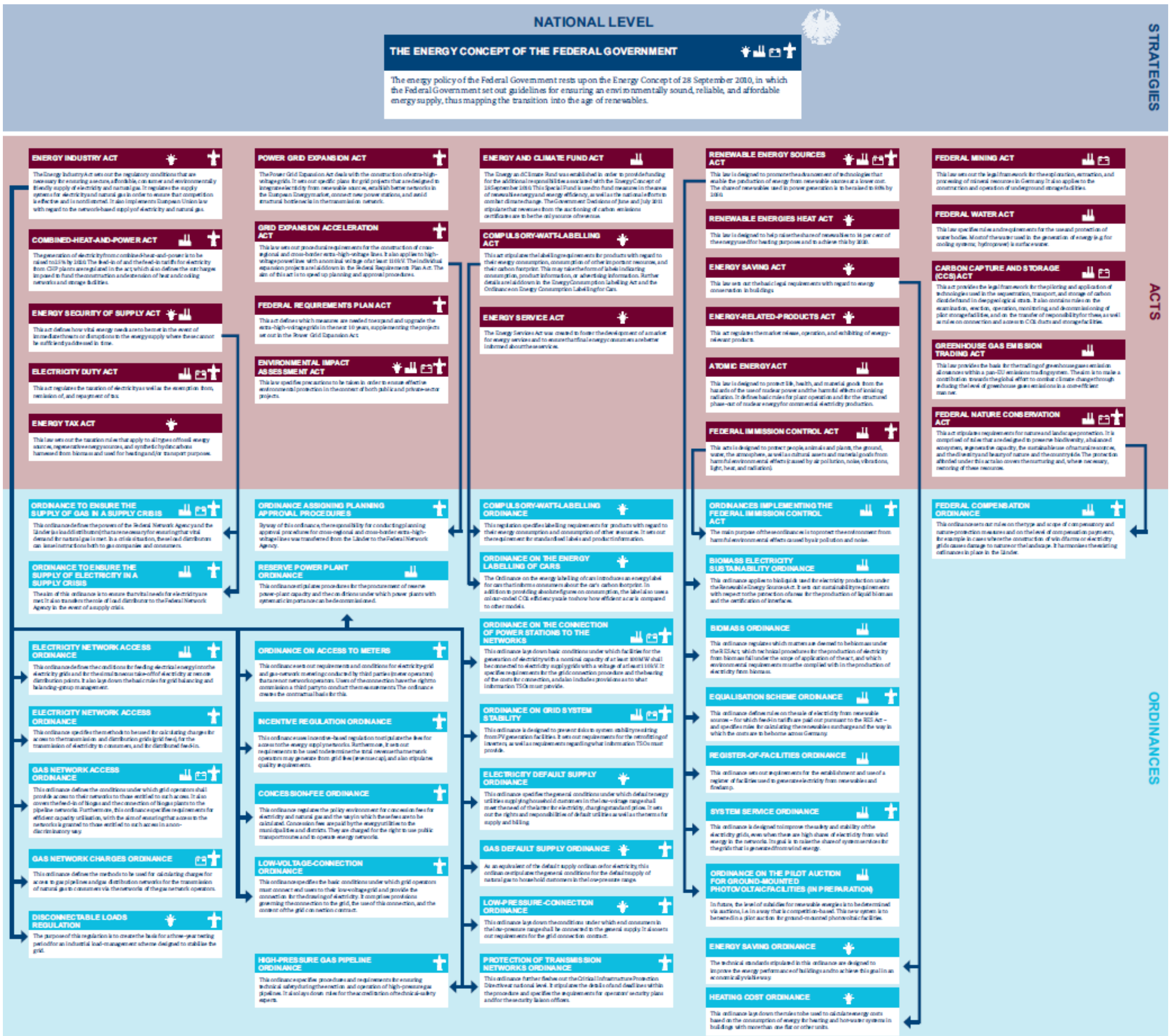


Figure 14: Federal regulatory framework for energy in Germany [BMWi 2014]

Elements of this complex Figure 14 are discussed in this study as far as relevant to the business cases analysed in chapter 0. It has to be noted, that the regulatory framework has been developing and regularly changing in the course of the past 20+ years of

“Energiewende” (energy transition) and the lessons-learnt from that. It can be expected that further significant adaptations are to be made within the next 5 to 10 years. This makes energy regulatory a volatile, moving target, which has strong repercussions on the robustness of business model results. To get a methodological grip on these uncertainties, transparency is given by depicting the relevant cost/price components in the business models.

With regard to **fees and taxes** that are due when consuming electricity, Table 5 and Table 6 give an overview over relevant regulations in Germany.

Table 5: Characteristics of fees and taxes in price components (Source: netztransparenz.de)

Component	Explanation
EEG-Appropriation	The EEG-appropriation results from the compensation and market premiums that must be payed to the network suppliers by the energy providers.
Network use fees	Fees for network use (Network infrastructure, Energy transport loses) that are charged by the energy providers are dependent on the amount of voltage used by the network providers.
KWK-Appropriation (cogeneration)	Nationwide balance with regard to the payment from the KWK-surcharges (to promote the coupling of power and heat) through the network provider (surcharge on the NNE).
Offshore-Appropriation	Results from the damage reimbursement payed to the suppliers of Offshore energy for disruption of network connectivity which can be charged to the network providers.
StromNEV §19 Appropriation	Lost revenues from the network provider resulting from individual network fees. Nationwide distribution.
Concession fee	Fees for use of public transit for the construction and distribution of electrical wires, with the respective municipal consent on delivery rates to be payed to the municipalities.
Supply management	Reduction of the RES-/cogeneration-supply resulting from network overload is to be compensated by the energy suppliers. Costs can be re-directed to the network consumers. Without nationwide distribution.
Costs according to § 10 SysStabV	Upgrades to solar panels, to be provided by network distributors – up to 50% of the associated costs re-directed to the network consumers, without nationwide distribution.
Electricity tax	Taxation of electrical energy consumption in German tax regions. The tax is applied when an end consumer extracts energy from a tax region resident supplier’s energy supply.

Table 6: Legal basis

Component	Legal basis
EEG-Appropriation	§ 60 Paragraph 1 EEG 2014 (Erneuerbare-Energien-Gesetz from 21 Juli 2014 (BGBl. I, p1066)), previously changed through Article 1 in the law from 22 December 2014 (BGBl. I, p2406). Implementation: § 3 Paragraph 3 and 4 plus § 6 AusglMechV. In a separate regulation according to § 91 no. 7 EEG 2014 is controlled by self-powered energy generation.
Network use fees	Regulations for charges for the access to electricity supply networks (StromNEV) from 25 July 2005 (BGBl. I, p2225), previously changed through Article 312 in the regulations from 31 August 2015 (BGBl. I, p1474).
KWK-Appropriation	§ 9 Kraft-Wärme-Kopplungsgesetzes/KWKG from 19 March 2002 (BGBl. I, p1092), previously changed through Article 4 Paragraph 5, 7 of the law from 7 August 2013 (BGBl. I, p3154).
Offshore-Appropriation	§ 17f EnWG (Energiewirtschaftsgesetz) from July 7, 2005 (BGBl. I, p1970, 3621), previously changed through Article 3 Paragraph 4 of the law from October 4, 2013 (BGBl. I, p3746).
StromNEV §19 Appropriation	The lost revenues are re-allocated to all end consumers according to § 19 Paragraph 2 Sentence 14 StromNEV corresponding to § 9 KWK-G.
Concession fee	Concession fee regulations from January 9, 1992 (BGBl. I, p12, 407), previously changed through Article 3 Paragraph 4 of the regulation from 1 November 2006 (BGBl. I, p2477) and § 48 EnWG.
Supply management	§ 15 EEG 2014
Costs according to § 10 SysStabV	Costs according to § 10 of the system stability ordinance (SysStabV) from 20 July 2012 (BGBl. I, page 1635), previously changed through Article 1 of the regulation from 9 March 2015 (BGBl. I, p279).
Electricity tax	§ 5 Paragraph 1, p1, Stromsteuergesetz (StromStG) from 24 March 1999 (BGBl. I, p378; 2000 I, p147), previously changed through Article 242 of the regulation from 31 August 2015 (BGBl. I, p1474).

Case-specific, different exemptions from taxes and fees apply to reduce the electricity costs. These cost items for electricity supply are thus described in the following chapters 2.3.1, 2.3.2, and 3.3.3.

2.3.2 Provision of ancillary grid services and associated revenue

Provision of services to the power grid can constitute a significant part of the revenues of a power-to-gas system. The revenue prospects and conditions for becoming and actor on this market are described below for France and Germany respectively.

France

In France the Transmission System's Operator (TSO), RTE, has the obligation to ensure the equilibrium between offer and demand, the quality of electricity, its availability and the security of the network. To do so, RTE relies on system services. There are two types of system services: the regulation of frequency and the regulation of tension. Both frequency and tension must be maintained at a given level (or within a given bandwidth) for electrical equipment to function optimally, to ensure offer and demand equilibrium at all times and to guarantee the security of the network. Hereafter, only frequency services will be discussed as it is the only system service the semi-centralised power-to-hydrogen system is eligible to.

To guarantee balance at all times between electricity production and consumption, RTE has three reserves at its disposal: the primary reserve, the secondary reserve and the tertiary reserve (also known as the adjustment mechanism). RTE can either use the reserves to inject or to withdraw power from the grid. RTE draws upon these reserves as needed depending on the circumstances of disequilibrium. As a result, the required capacity volumes are different as are the actors which may contribute to these reserves. Lastly, prices on the primary and secondary reserves are not set in the same way as they are on the tertiary reserve. In this section, first, the use of each reserve will be presented as will its capacity requirements for France. Thereafter, who can contribute to the primary reserves and how they are remunerated will be presented. The secondary capacity market for primary and secondary reserves which was introduced in 2014 will also be presented. Finally, we shall present the actors eligible to provide capacity in the tertiary reserve and how prices are set. This will allow us to explain the services the electrolyser can contribute to.

For any disequilibrium within a 15-minutes timeframe, frequency is regulated automatically, within the 15 to 30 seconds following instability, via the primary reserve which is connected to the European Synchronous Continental plate.

Set at European level, the primary reserve levels must reach 3 000 MW; France being responsible of guaranteeing 600 MW.

The primary reserve is activated temporarily (for a maximum of 15 minutes) to restore equilibrium as soon as unbalance appears, providing time for the activation of secondary reserves which are needed for restoring nominal frequency and for providing the required adjustment as long as needed. For longer disruptions, tertiary reserve is activated in order to restore the availability of secondary reserve for addressing new potential sources of unbalance.

In France, the secondary reserve power capacity requirement varies depending on the time of day and year from 500 MW up to 1500 MW. It is calculated on a half hourly basis. Both primary and secondary reserves are automatically activated.

Tertiary reserve capacity is composed of two lots: one mobilisable within 15 minutes and the other within 30 minutes. The required capacity for each of these lots varies on an annual basis. On average, the 15-minute reserve capacity amounts to 1000 MW and the second to 500 MW.

In France, two types of actors contribute to the primary and secondary reserves: obligated actors and voluntary actors. All power generation units connected to the high frequency network must contribute to the primary frequency reserves if their capacity is beyond 40 MW for new plants and 120 for old units -i.e. built before the 30th of December 1999. Equally, all power production units beyond 120 MW must contribute to the secondary frequency reserve. However, non-obligated actors who wish to contribute to the primary and secondary reserves may do so by entering a contract with RTE. Whether obligated or contributing voluntarily to these reserves, the Responsable de Réserve (hereafter ARP) enters a contractual relationship with RTE. Irrespective of the obligatory or voluntary contribution, any actor must meet given criteria to play a part on the primary and secondary reserve.

For both reserves, the Reserve Entity (ARP), must be able to provide a minimum of 1 MW for a half-hourly time frame. No one actor can contribute more than 150 MW capacity to the primary reserve. The level of obligation is split amongst all contributors to primary and secondary reserves depending on their production capacity. Conditions for access to the tertiary reserve are different.

In July 2014, a secondary market for capacity withdrawal was set up on an experimental basis. As a result, individual actors may bid their power on the primary and secondary markets. Under these new rules, ARPs may fulfil their primary and secondary reserve obligations by purchasing withdrawal capacity via over-the-counter contracts. However, as this is an experimental scheme, the TSO has capped the maximum amount of capacity which may be contracted by obligated actors. Currently, only 80 MW capacity may be contracted. Furthermore, no given individual obligated actor may contract more than 40 MW.

In the primary and secondary reserve, the price for capacity and power is fixed by the TSO. In compensation for the provision of capacity, the TSO provides the ARPs with a fixed compensation based on the capacity they offer and a fixed compensation for the power they provided to restore equilibrium. The set price for capacity for 2016 is 9.098 € per MW per half hour or 18€ per MW per hour. If the capacity is called upon, then the ARP receives an additional payment for the energy supplied which is set is 10.474 € per MWh [RTE 2015].

For the tertiary reserve, only actors with a capacity of minimum 10 MW may contribute to the 15-minute reserve capacity. As of 2016, actors with a capacity between 1 MW and 10 MW can contribute to the 30-minute tertiary reserve capacity [RTE 2015].

Providing capacity volumes for the tertiary reserve is voluntary. The required levels for this reserve are set a year ahead of time via public tenders published in January. Actors declare the amount of capacity they wish to provide (whether injector or withdrawal or both) over the next year to the TSO and enter into a contractual relationship. Thereafter, on a daily basis, the actor must provide the TSO with its available capacity for either injection or withdrawal for the following day on a half-hourly basis at one of the online desks at 16h, 22h and 23h on day-1. Power producers, and power producers alone, must provide a production programme by 16h on day-1. Within the day, until 21h, actors may modify the submitted capacity offer.

The capacity offer is composed of a direction (injection or withdrawal), a validity period and, eventually of a different price over six 4-hour time frames.

The TSO will evaluate the required capacity to ensure that frequency can be regulated for any half-hour on its entire perimeter. The placed bids are then organised following the economic optimum with the cheapest bids being called upon first, as needed. Actors on the tertiary reserve are remunerated if their capacity is called upon at the price they bid.

Table 7: Main characteristics of the French tertiary reserve (source: [RTE, 2015])

Product	Tender period	Minimum lot size	Duration	Compensation	market size 2013
Tertiary reserve	daily	+/- 1 MW	four 6-hour time slots	pay-as-bid (power and capacity price)	?

Prices on the adjustment mechanism therefore depend on the type of imbalance and whether the provided capacity is for injection or withdrawal. The figure below presents the average price of capacity on the tertiary reserve market in France for injection and withdrawal of power from 2012 to 2015.

Table 8: Average prices on the tertiary reserve in France from 2012 to 2015 (source: http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/histo/tendances.jsp)

(€/MWh)	Tertiary reserve	
	positive	negative
2012	51.687	39.522
2013	48.759	30.685
2014	38.383	30.889
2015	41.912	37.909
2030	*	*

The semi-centralised power-to-hydrogen can provide system services both by selling its adjustment capacity (withdrawal or injection by increasing or reducing load) on the secondary frequency regulation market or by bidding its capacity (whether for injection or withdrawal) onto the adjustment mechanism.

The first option would provide, a priori, both greater foresight and amounts of revenues as prices are set in MW/hour. However, since this market is an over-the-counter market, the price paid by ARP's for withdrawal capacity is not readily available. Nonetheless, seeing as frequency regulation services are remunerated on average 18 €/MW per hour, it would be safe to assume that the contracted capacity price would be similar.

The electrolyser, with its 1 MW capacity, could bid into the tertiary reserve. However, in the context of this study, only the option to provide system services to the primary and secondary reserves via the secondary market was taken into consideration as calculating the French adjustment requirement needs for each half-hour of the year was considered beyond the scope of this study.

Germany

Energy reserves [control power /operating reserve/controlling power range] are required to keep current consumption and power supply in equilibrium at all times and compensate for any deviations in the short term. The TSO (Transmission System Operator) obtains [contracts] the used [required] energy reserves [control power/operating reserve/controlling power range] on the open market. The procurement of energy reserves [control power/operating reserve/controlling power range] occurs through competitive bidding on a tender basis in the German control power market with the participation of numerous suppliers (both power plant generators and consumers).

To obtain access to the respective markets potential suppliers have to undergo a technical prequalification. They must prove that they can guarantee the necessary requirements to ensure the security of supply for the provision of one or more types of energy reserves [control power/operating reserve/controlling power range]. For all types of control energy prequalification is carried out exclusively by the TSO, in whose control area the respective technical units are connected, regardless of the voltage level grid.

In principle, all technical units which meet the prequalification requirements can prequalify for participating in the balancing power market regardless of the technology. This can include e.g. electric motors or electrolysers (PtG).

Revenues may be generated with power-to-gas plants through the provision of **ancillary grid services**.

The national legal framework covers the control and balancing [imbalance] energy in the Electricity Network Access Ordinance (StromNZV) as well as directly the Energy Industry Law (EnWG). The Renewable Energy Law (EEG) lays down rules for the participation of electricity generation plants based on renewable energies for balancing energy markets.

The market regulations and conditions for access to the individual control performance qualities are determined by the Federal Network Agency (resolutions BK 6-10-097, BK 6-10-098, BK 6-10-09, dated November 2015).

Table 9 gives an overview of the main currently applicable framework conditions.

Table 9: German balancing power market conditions (Source: regelleistung.net)

Product[12]	Tender period	Minimum lot size	Duration	Compensation	market size 2013
Primary control reserve (PCR)	weekly	1 MW	1 week	pay-as-bid (power price)	n.a.
Secondary control reserve (SCR)	weekly	+/- 5 MW	Mon-Fri: 8 – 20; and remaining time	pay-as-bid (power and working price)	354 Mio. €
Minute reserve (MR)	daily	+/- 5 MW	six 4-hour time slots	pay-as-bid (power and working price)	155 Mio. €

Based on the "The ordinance on Interruptible Load Agreements" (AbLaV), dated 28.12.2012, providers of dispatchable loads can be contractually bound for the purpose of maintaining the network and system security. Interruptible loads are here regarded as large/major consumption units which are connected to the high and ultra-high voltage network (transmission grid). With these units, large amounts of electricity are nearly constantly drawn and they can, upon notice, reduce their consumption at short notice and for a pre-defined minimum duration. Products: immediately interruptible loads and fast interruptible loads. The AbLaV is an instrument for ensuring security of supply. The AbLaV as per 28 December 2012 (BGBl. I, p2998) changed by Article 316 of the ordinance of 31.08.2015 (BGBl. I, p1474) is expected to be prolonged until the 30 June 2016. A corresponding ordinance modifying the AbLaV is currently in legislative procedure.

For the delivery of the required ancillary service inputs, the transmission system operator (TSO) pays the providers appropriate remuneration according to contractual arrangements. The investments into plant components needed in order to provide ancillary services are borne by the supplier.

The regulatory framework with regard to fees/taxes and ancillary services has been changing regularly over the past 10 years. Further changes in the governing regulatory mechanisms are likely – including fundamental ones – with further deployment of renewable power plants, additional electricity consumption for heat, transport, etc, and not least with new integration options reaching technical maturity.

For the power-to-gas business cases, relevant fees and taxes as well as potential revenues from ancillary grid services are depicted in chapters 2.3.1. and 2.3.2.

Power-to-gas plants connected to the public grid[13] may generate additional revenues if tapping newly developing control power markets for ancillary grid services in Germany.

The control power markets differentiate between positive control power (i.e. load reduction), and negative control power (i.e. load increase).

From a technical point of view, the electrolyser 1 MW, 10 MW respectively, meets the requirements of all types of control reserve (compare chapter 2.2.3). If necessary, the PtG operator has to offer pooling with other technologies / provider. The offered product size for all product types doesn't have to be supplied by one single unit, but can be achieved by so-called pooling of several units by a central location.

However, the provision of primary control reserve is carried out as a symmetrical product that is both positive as well as negative control reserve has to be permanently provided. Since PEM electrolysers can be operated at 150% to 200% of nominal load for the duration required (30 minutes), the electrolyser will always be able to provide power to the primary control reserve.

Secondary control reserve and the minute reserve are easier to be offered insofar as positive and negative control reserve is separately tendered.

According to current rules and regulations, for both, the primary as well as the secondary control reserve the tendering period is one week, so the operator has to ensure provision for one week in the production period. The minute reserve is tendered on every workday.

Provision of reserve control is reimbursed at performance price and in the case of secondary control and minute reserve the additional request of this service is reimbursed with a contract price. At first the bid prices of the tenderers are collected for the performance price and sorted in ascending order. The award for the service provision (power supply) will be made independently of the contract price, however is pre-requisite for a possible service provision. For the tenderers being awarded the service provision, offered contract prices are sorted in a way, that tenderer with low contract prices win the bid at first.

As demand is difficult to predict, the amount of hydrogen produced in the control reserve market is difficult to calculate in advance. This fact could be an obstacle to possible supply contracts asking for a certain amount of production volume.

Revenue generated in the control reserve market depends decisively on the offered performance price. If the performance price is low, the bidder will lose part of the possible revenues. If the demand rate is too high, it can be that the bid will not be rewarded at all.

With regards to the performance prices, there are extreme differences between the types of control reserve, the months and years and the different product time slices. In the table below you can see the annual total and the average performance prices from the control reserve auctions.

[13] Provision of ancillary grid services without connection to the public electricity grid is not possible.

The following Table 10 depicts the average prices of different German balancing power products.

Table 10: Average prices for balancing power in Germany (Source: http://balancepower.de/regelleistung.html)

(€/MW)	Secondary control reserve		Minute reserve	
	positive	negative	positive	negative
2012	21,900	100,120	5,370	26,610
2013	66,150	99,970	8,310	50,040
2014	65,830	43,410	4,640	33,780
2015 (01-09)	38,080	17,160	4,240	9,910
2030	*	*	*	*

* No assumptions made as any assumption is highly speculative.

While Table 10 gives the annual average prices, it has to be noted that the intra-annual volatility of balancing power prices is high. Furthermore, prices are sensitive to the development of the regulatory framework, energy technology progress and not least the market behavior of bidders.

In the past, the secondary control reserve market was the most attractive because of the level of prices. Control reserve markets are subject to considerable fluctuations of prices difficult to predict which have led to a low price level in the most recent past. Increasing competitive pressure can lead to decreasing revenues for the tender as well.

3 DETAILED ANALYSIS AND COMPARISON OF SELECTED POWER-TO-GAS APPLICATIONS FOR FRANCE AND GERMANY

Based on the study teams' experience from earlier works in the power-to-gas field and on current discussions and market developments, the study team has chosen two applications with a significant potential to leverage the benefits of power-to-gas and help the sector reach the economies of scale needed to reduce technology cost in an accelerated way:

- Application A: Green hydrogen for use in refineries (3.1)
- Application B: Semi-centralised power-to-gas system supporting hydrogen mobility - business case studies (3.3)

In particular, both applications bridge two sectors that until now have been addressed separately: the power and the transport sector.

For both applications, the following elements will be reviewed in more detail and compared for Germany and France.

- Boundary conditions (energy system, infrastructure, policies, other);
- Value chains and major stakeholders involved;
- Requirements for an economically balanced operation;
- Environmental benefits (focus on GHG emissions);
- Deployment potential and (resulting) impact on addressing intermittency.

3.1 APPLICATION A: Hydrogen from power-to-gas for use in refineries

Refineries are major hydrogen consumers. Today, about 30% of global hydrogen demand for industrial use is hydrogen in refineries. Quasi all of this hydrogen stems from fossil sources. In the short term, there is an interesting potential to use large amounts of 'green' renewable hydrogen in refineries within the gasoline or diesel production process, thus effectively reducing their specific greenhouse gas (GHG) emissions and reducing specific electrolyser investments.

3.1.1 Regulatory framework

With regard to Application A, i.e. the use of green hydrogen in refineries, key regulatory elements are the EU Fuel Quality Directive (FQD) and its national implementations in France and Germany. In the chapter 2.2.4, details on the regulatory framework are laid out. For a condensed overview and comparison of regulatory elements relevant to the use of green hydrogen in refineries, selected aspects of the EU FQD, the German BImSchG/V and French Code de l'énergie implementation are depicted in Table 11.

Table 11: Overview regulatory framework EU FQD, German BImSchG/V and French Code de l'énergie

Criteria	EU FQD	France Code de l'énergie	Germany BImSchG/V
Lifetime	2020		2020
GHG targets	-2 % by 2015 -4 % by 2017 -6 % by 2020	-10% by 2020:	-3.5 % by 2015 -4 % by 2017 -6 % by 2020
Responsibility	Supplier	Energy tax responsible entity (usually the fuel refinery)	Energy tax responsible entity (usually the fuel refinery)
Options			
upstream:	Flaring/venting	Flaring/venting	–
refinery:	–	Refinery GHG emissions reduction	–
downstream:	Biofuels and alternative fuels from non-biological sources	Biofuels, electricity	Biofuels
Hydrogen	Eligible as transportation fuel 21.1 – 93.8 g $CO_{2equiv.}$/MJ, depending on hydrogen source (2015/652/EU, ANNEX I) Not for use in refineries yet	H_2 not yet eligible as transportation fuel Reduction of refinery emissions through use of low carbon hydrogen is eligible	H_2 not yet eligible; 'further renewable fuels' (e.g. PtG) and 'other measures' are subject to enforcement of a legal ordinance (§37d (2), point 13
Infringement	Subject to national implementation, which shall be 'effective, proportionate and dissuasive'	Not yet defined	470 €/t $CO_{2equiv.}$
Fuel baseline standard 2010	94.1 g/MJ	Not yet defined	83.8 g/MJ

With 470 €/t $CO_{2equiv.}$, the penalties for non-compliance are significant in Germany. What might look excessive at first sight is in fact a necessary level of fines as greenhouse gas mitigation options related to renewable fuels and improved/novel powertrains typically are in the order of many hundreds of Euros per ton of avoided greenhouse gas emissions.

For the time being, there are no regulatory grounds for renewable hydrogen to be used in refineries and accounted for in greenhouse gas emission reduction targets, neither with the FQD, nor with the German BImSchG. For France, the French Code de l'Energie does not specify eligible technologies; hydrogen may therefore be considered as a possible option.

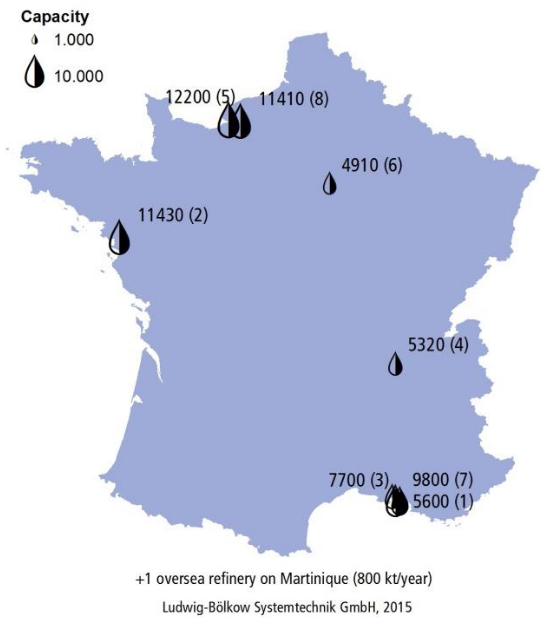
3.1.2 Refinery landscape

France

There are eight crude oil refineries currently operating in France, plus one in France territory Martinique. Refinery installed capacity ranges from 4.9 to 12.2 million tons per year. Major refinery operators and fuel distributors in France are Total and ExxonMobil. Figure 15 depicts where refinery capacities are installed in France.

Atmospheric distillation capacity

[x 1000 tons/year]



(1) Raffinerie de Fos (Fos-sur-Mer)

(2) Raffinerie de Donges

(3) Raffinerie de la Mede

(4) Raffinerie de Feyzin

(5) Raffinerie de Normandie (Gonfreville L'orcher)

(6) Raffinerie de Grandpuits

(7) Raffinerie de Lavéra

(8) Raffinerie de port-Jérôme-Gravenchon

Not on map:
Raffinerie des Antilles
(Fort-de-France, Martinique)

Total capacity: 68.4 million t/yr

Figure 15: Crude oil refineries in France (source: LBST based on [MEDDE 2015, no 14, fig 8] data)

According to [MEDDE 2015, no 11, fig 6] France imported in 2014 a total of 53.6 million tons of crude oil. Key exporting countries to France were Saudi Arabia (11.1 million t or 20.7%), Kazakhstan (7.1 million t or 13.3%), Nigeria (6.1 million t or 11.4%), Russia (5.2 million t or 9.8%), Norway (4.3 million t or 8%), Algeria (3.7 million t or 6.9%), Angola (3.2

million t or 5.9%), Libya (3.0 million t or 5.6%), Azerbaijan (2.6 million t or 4.8%), UK (1.4 million t or 2.5%), et al. (2.8 million t or 5.2%). Figure 16 depicts French crude oil origins by world region.

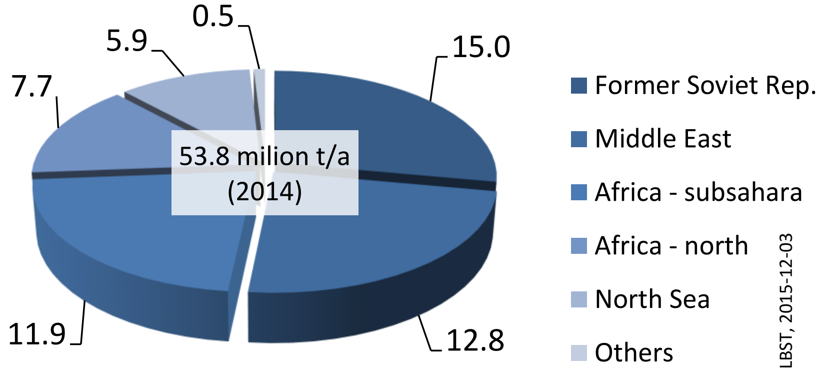


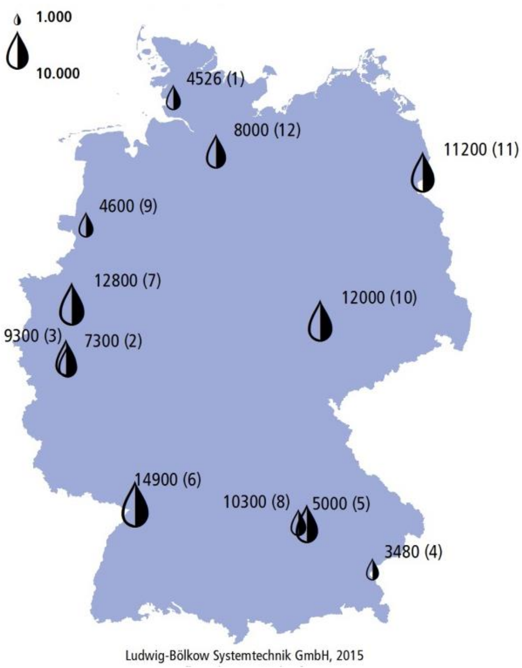
Figure 16: Crude oil imports to France in 2014 in 1000 t/yr by world region (source: LBST based on [MEDDE 2015, no 11, fig 6] data)

Germany

Currently, there are 12 refineries operating in Germany. The installed refinery capacity ranges from 4.5 to 12 million tons per year. Figure 17 depicts the refineries, capacities and their location in Germany.

Atmospheric distillation capacity

[x 1000 tons/year]



(1) Raffinerie Heide
(2) Shell Rheinland Raff. Wessling
(3) Shell Rheinland Raff. Godorf
(4) OMV Deutschland (Burghausen)
(5) Gunvor Raffinerie Ingolstadt
(6) Miro Karlsruhe
(7) Ruhr Oel (Gelsenkirchen)
(8) Bayernoil (Vohburg)
(9) Erdölraffinerie Emsland (Lingen)
(10) Total Raffinerie Mitteldeutschland (Spergau)
(11) PCK Raffinerie Schwedt
(12) Elbe Mineralölwerk Harburg & Holborn Europa Raffinerie

Total capacity: 103,4 million t/yr

Figure 17: Fuel refineries in Germany (source: LBST based on [MWV 2015] data)

In 2014, Germany imported 89.4 million tons of crude oil. Key exporting countries to Germany are Russia (30.0 million t or 33.6%), Norway (15.2 million t or 17.0%), Great Britain (9.7 million t or 10.9%), Nigeria (7.1 million t or 8.0%), Kazakhstan (68 million t or 7.6%), Azerbaijan (4.1 million t or 4.6%), Algeria (3.6 million t or 4.1%), and Libya (3.2 million t or 3.6%). Figure 18 depicts German crude oil origins by world region.

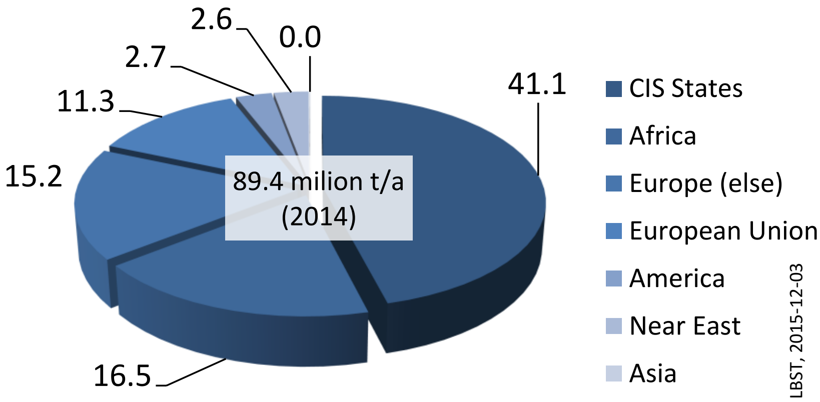


Figure 18: Crude oil imports to Germany in 2014 in million tons per year by world region (source: LBST based on [MWV 2015] data)

Comparison

France and Germany are among the 'top 5' countries in Europe with regard to the number of refineries and the total installed refinery capacity as Figure 19 shows.

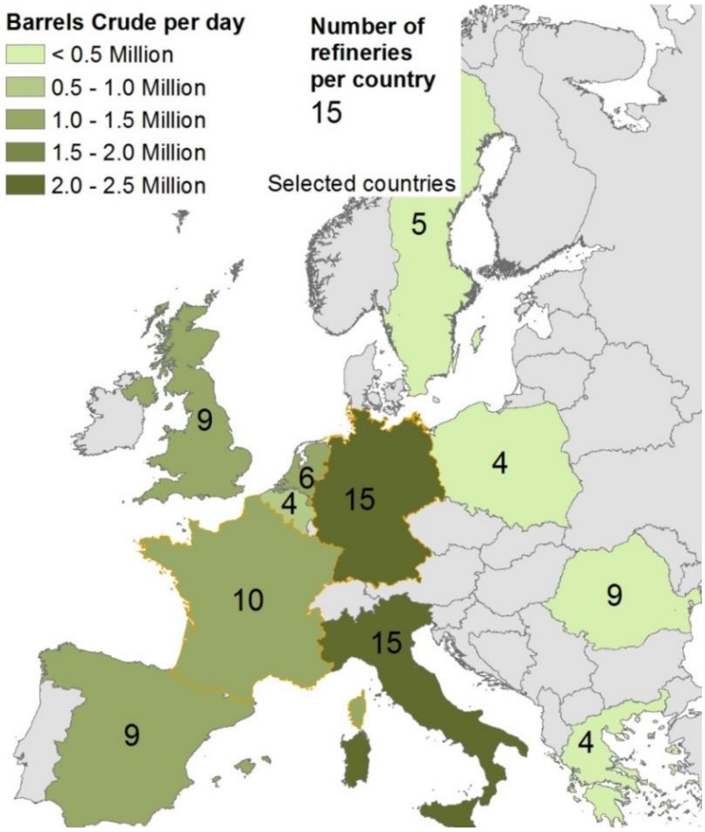


Figure 19: Major refining and processing capacities in Europe (source: LBST based on [E3M et al. 2015, p12] data)

Germany is the leading refinery location in Europe, by installed distillation capacity as well as by the number of refineries installed in Germany, followed suit by Italy. Close to the UK, **France** ranks fourth in Europe by number and capacity. Together, Germany and France correspond to a share of 20 % capacity and 23 % of refineries in Europe.

Generally, there is a trade-off between costs and quality with crude-oil as refinery feedstock. The processing of lower quality crude-oil requires a different refinery layout than vice versa. Hence, the processes installed in refineries today have been established and developed over decades and are fine-tuned to strike the balance of costs versus feedstock quality. From Figure 20, it can be observed that a wide range of crude-oil quality portfolios are used in European refineries. The average crude-oil gravity is 36.1 API with an average sulphur content of 0.7 % by weight [EXERGIA et al. 2015, p167].

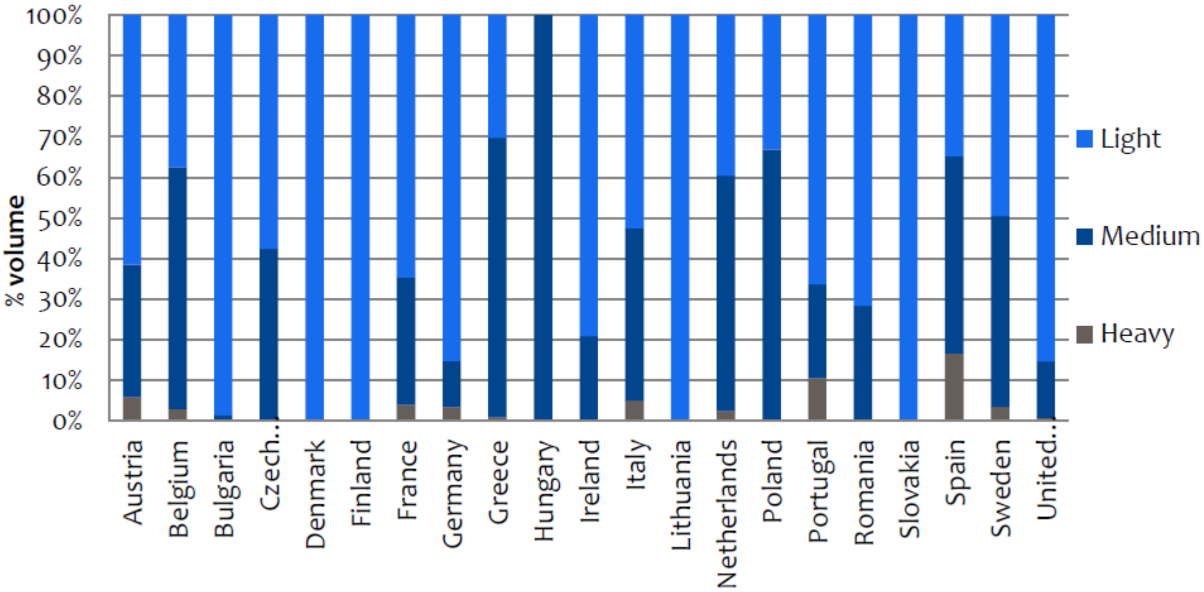


Figure 20: Share of crude oil qualities in European refineries [EXERGIA et al. 2015, p166]

The crude-oil qualities processed in **France** (36.0 API gravity and 0.7 wt.-% sulphur on average [EXERGIA et al. 2015, p167]) are very representative for the spectrum of qualities processed in European refineries.

The crude-oil qualities processed in **Germany** tend to be on the lighter side with an average of 37.3 API gravity and 0.5 wt.-% sulphur [EXERGIA et al. 2015, p167]. Some 85 % of crude-oil processed in Germany is of 'sweet crude' type, i.e. have an API gravity greater 35 and sulphur content below 0.8 wt.-%. This leads to lower needs for desulphurisation and upgrading compared with the majority of other EU Member States. Only countries like Bulgaria, Denmark, Finland, Lithuania and Slovakia source and process lighter crude-oils than Germany, whereas neighbouring countries Austria, Italy and Poland process significantly heavier crude-oils.

The efforts for crude-oil processing are likely more pronouncedly rising in Germany than in France in the future.

Figure 21 depicts the product portfolios of European refineries.

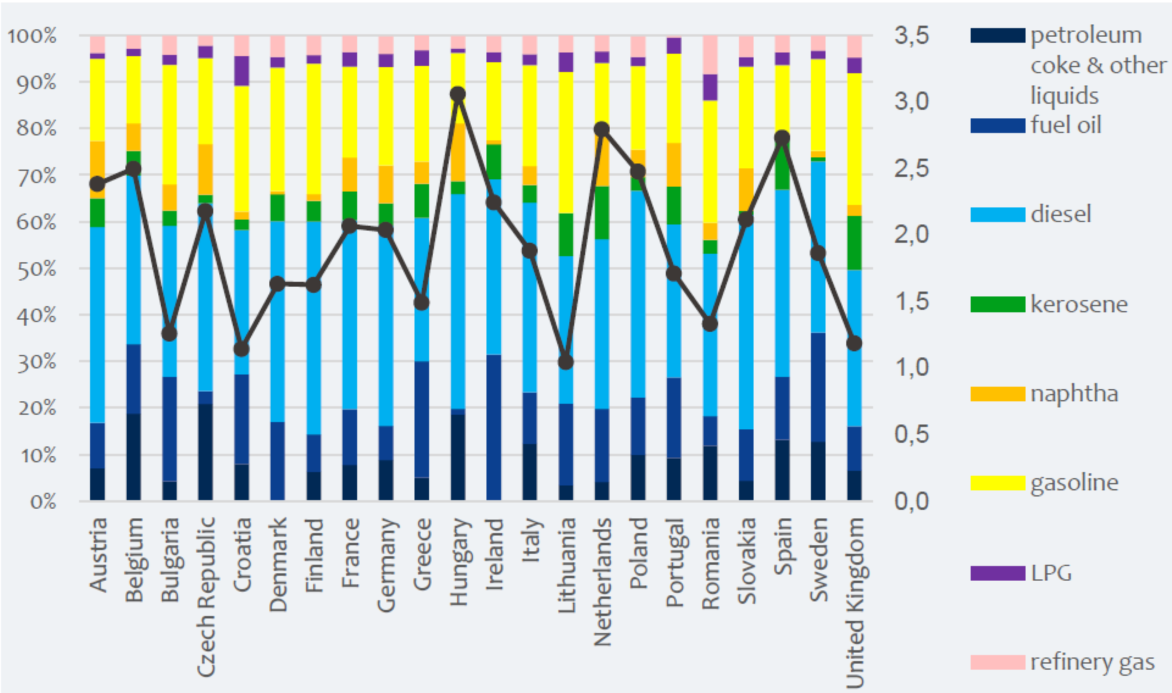


Figure 21: European refineries' product mixes (%, left scale) and diesel-to-petroleum ratios (D/P, without unit, right scale) [EXERGIA et al. 2015, p170]

The product mix from European refineries is diesel oriented (31-49% diesel, 13-30% gasoline, 1-12% kerosene – in % of total refinery output). There are only marginal differences between the French and German refineries' product mixes. Both are well within the average of European refinery product mixes and are thus representative of the European refining sector.

3.1.3 Hydrogen use in refineries

To produce gasoline, kerosene, and diesel from crude oil refining, hydrogen is required in several processes. In this study the impact of substitution of hydrogen from natural gas steam reforming by hydrogen from renewable electricity has been assessed.

Role of hydrogen in refineries

In refineries, hydrogen is produced as a by-product from the reformer/platformer and from the Fluid Catalytic Cracking (FCC) process, and used to manage the sulphur, benzene, and aromatic contents of the final products in processes like desulphurisation and hydrotreating, and to convert heavy products to lighter products via hydrocracking. However, the hydrogen from the FCC has not been taken into account because it is used as fuel for heat supply within the refinery due to the relatively low amount and low purity.

Each refinery is unique with regard to refinery design and applied processes. However, typically there remains a lack of hydrogen supply ('net H_2 demand') that is filled with dedicated hydrogen production from natural gas via steam-methane reforming (SMR).

Net hydrogen demand from refineries increases with the density (API gravity) and sulphur content of the crude oil. Furthermore, decreasing demand of heavy products (HFO) and increasing demands of lighter products (gasoline, kerosene, diesel) result in conversion of HFO in hydrocracking plants for which additional hydrogen is required. Stricter emission standards are a driver for this, e.g. in maritime shipping.

France

From the capacity of the different refinery processes used in French crude oil refineries indicated in [MEDDE 2015] and the specific hydrogen consumption and production of these processes the net hydrogen demand can be calculated. The net hydrogen demand of the refineries which has to be met by an additional hydrogen source such as natural gas steam reforming is lower than the hydrogen production capacity indicated in various literature sources (e.g. [DOE 2015]).

A synthetic 'refinery France' has been modelled. Figure 22 shows the various processes for the 'Refinery France'.

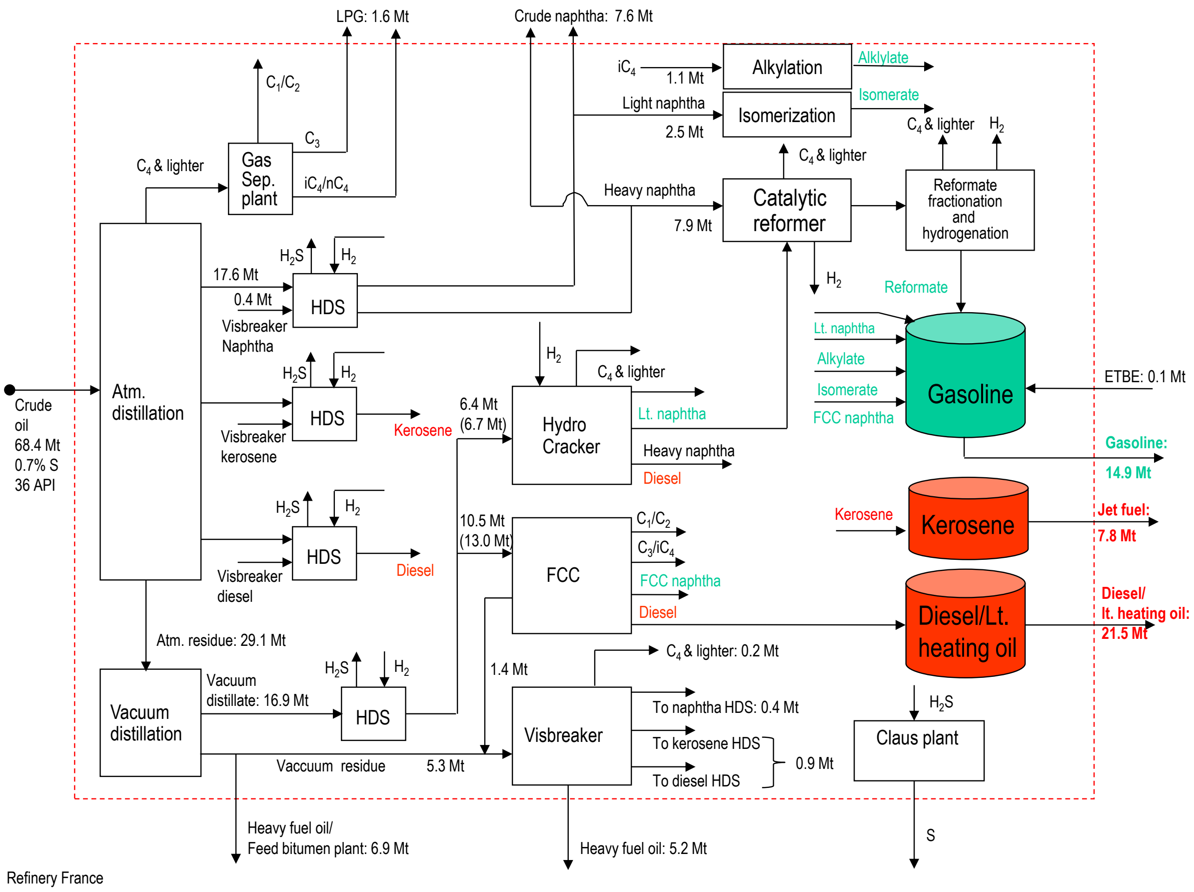


Figure 22: Synthetic refinery France (source: LBST refinery model)

For the average crude oil properties used in French refineries indicated in [Exergia et al 2015] the amount of vacuum distillate is lower than the capacity of hydrocracking and fluid catalytic cracking (FCC) plants indicated in [MEDDE 2015] which could treat this streams. Probably the capacity of the hydrocracking and FCC plants is adapted for more flexible refinery operations varying crude oil qualities.

In this study the hydrogen demand has been calculated based upon the specific hydrogen demand of the various processes (hydrocracking, FCC, vacuum distillate desulphurization, middle distillate desulphurisation, and naphtha desulphurisation) which depends on the sulphur content of the feedstock of these processes. The sulphur content of the feedstock of these processes depends on the sulphur content of the crude oil. According to [Exergia et al 2015] the average sulphur content of the crude oil mix used in French refineries amounts to about 0.7% (mass). At the atmospheric distillation and the vacuum distillation stage the sulphur is enriched in the heavier fraction. The equations for calculation of the sulphur content of the different fractions have been derived from [FZJ 1994].

Table 12 shows the hydrogen demand and supply of crude oil refineries.

Table 12: Hydrogen demand and production of French crude oil refineries (kt/yr)

Refinery process	H_2 demand	H_2 production	Net H_2 demand
Hydrocracking	220.3		
Vacuum distillate desulfurisation	29.2		
Middle distillate desulfurisation	48.9		
Naphtha desulfurisation	21.7		
FCC cracker	-	0*	
Catalytic reformer	-	158.9	
Total	**320.1**	**158.9**	**161.3****

* Hydrogen from fluid catalytic cracking (FCC) plus other gases for heat supply
** Assumed to be supplied by steam-methane reformer (SMR)

In France, the net hydrogen input of crude oil refineries amounts to about 0.24% of the crude oil input based on the mass of hydrogen and crude oil or about 0.66% based on the lower heating value (LHV) of hydrogen and crude oil. As a result, an additional hydrogen generation capacity of about 161 kt per year (or 204,600 Nm^3/h) is required. Since the equivalent full load period of crude oil refineries (and also steam methane reforming plants) is lower than 8760 hours per year the annual hydrogen is slightly lower.

Germany

Using the capacity of the different refinery processes used in German crude oil refineries indicated in [MWV 2015] and the specific hydrogen consumption and production of these processes, the net hydrogen demand can be calculated. The net hydrogen demand of the refineries which has to be met by an additional hydrogen source such as natural gas steam reforming is lower than the hydrogen production capacity indicated in various literature sources (e.g. [DOE 2015]).

For the calculation of the hydrogen demand the same approach have been applied as for France. The sulphur content of the crude oil used in German refineries amounts to about 0.5% (mass) [Exergia et al 2015].

In Germany there are also gasification plants which convert visbreaker residue to synthesis gas which consists of hydrogen and carbon monoxide. The gasifiers are located in Wesseling, Gelsenkirchen, and Spergau/Leuna. This hydrogen source has not been taken into account because the hydrogen is used for processes outside the refinery. Methanol synthesis plants are located onsite the gasification plants. Furthermore, a part of the hydrogen from the gasification plant in Spergau is probably sent to a hydrogen liquefaction plant with a capacity of 5 t of hydrogen per day at the Leuna chemical complex.

Table 12 shows the hydrogen demand and supply of crude oil refineries.

Table 13: Hydrogen demand and production of German crude oil refineries (kt/yr)

Refinery process	H_2 demand	H_2 production	Net H_2 demand
Hydrocracking	327.2		
Vacuum distillate desulphurisation	22.3		
Middle distillate desulphurisation	65.1		
Naphtha desulphurisation	37.0		
FCC cracker		0*	
Catalytic reformer		307.7	
Total	**452.1**	**307.7**	**144.4****

* Hydrogen from fluid catalytic cracking (FCC) plus other gases for heat supply
** Assumed to be supplied by steam-methane reformer (SMR)

In Germany, the net hydrogen input of crude oil refineries amounts to about 0.14% of the crude oil input based on the mass of hydrogen and crude oil or about 0.39% based on the lower heating value of hydrogen and crude oil. As a result, an additional hydrogen generation capacity of about 144 kt per year (or 183,200 Nm^3/h) is required. Since the equivalent full load period of crude oil refineries (and also steam methane reforming plants) is lower than 8760 hours per year the annual hydrogen is slightly lower.

LCA hydrogen pathways and use in refineries (per MJ fuel out)

Figure 23 depicts the calculation boundaries of main refinery inputs and outputs.

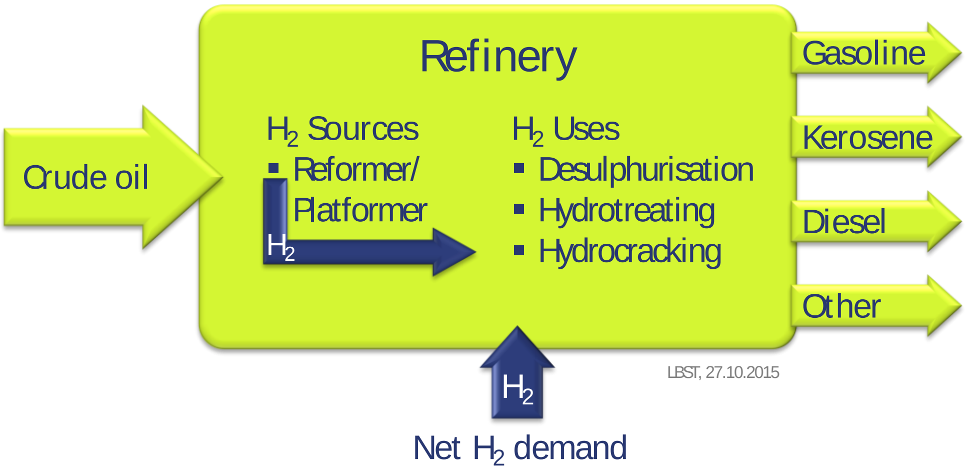


Figure 23: Hydrogen sources and uses in refineries (source: LBST)

The net hydrogen demand is calculated from the balance of refinery internal hydrogen streams:

Net H_2 demand = H_2 process sources – H_2 process uses

Desulphurisation is a sensitive parameter to the net hydrogen demand in refining. By tendency, the crude oil quality is further deteriorating (increasing sulphur content). From the latest US EIA and IEA statistics it can be derived, that the share of conventional crude oil in the world mix was about 84 % in 2005 (peak year of conventional crudes). In 2014, the share of conventional crude oil was about 75 %. At the same time, the overall amount of crude oil increased by about 8 million barrel per day between 2005 and 2014. Furthermore, the demand for heavy fuel oils (HFO) is prospectively decreasing due to the extension of maritime emission control areas (ECAs) where fuel burn in ships is restricted to low-sulphur and higher-value fuels.

For the hydrogen supply, the following pathways have been investigated:

- H_2 from piped natural gas (fossil hydrogen reference)
- H_2 from renewable electricity (wind, solar)

Figure 24 and Figure 25 show schematics of the pathways for the supply of gasoline and diesel including hydrogen supply from natural gas (fossil reference) and renewable power, respectively.

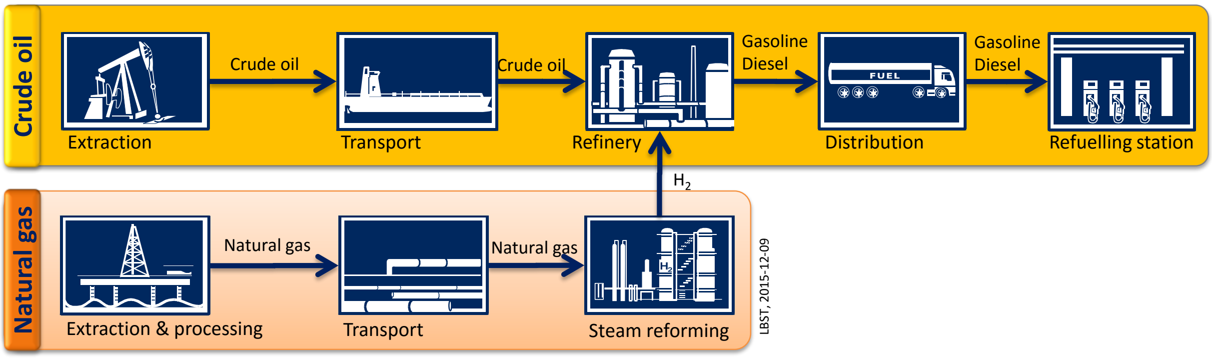


Figure 24: Schematic of the pathways for the supply of gasoline and diesel including hydrogen supply from natural gas (fossil energy-based reference) (source: LBST)

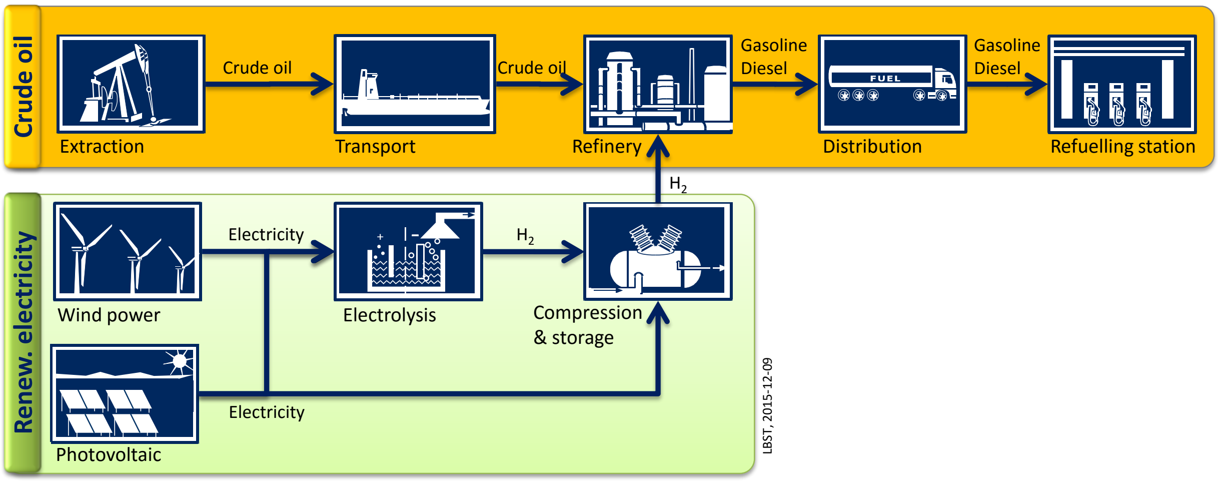


Figure 25: Schematic of the pathways for the supply of gasoline and diesel including hydrogen supply from renewable electricity (source: LBST)

The greenhouse gas (GHG) emissions from the supply of natural gas in France (13.9 g CO_2 equivalent per MJ of natural gas) and Germany (14.0 g CO_2 equivalent per MJ of natural gas) have been derived from [Exergia et al 2015].

About 55.1 g CO_2 per MJ of natural gas is generated by the combustion of natural gas. The natural gas consumption of large natural gas steam reforming plants amounts to 1.315 MJ per MJ of hydrogen based on the lower heating value [FW 1996] leading to about 72.4 g CO_2 per MJ of hydrogen (or 8.7 kg per t of hydrogen). Furthermore, small amounts of CH_4 (~0.016 g per MJ of hydrogen) are generated in the burner of the steam reformer. Table 14 shows the greenhouse gas emissions from the supply of hydrogen via natural gas steam reforming.

Table 14: Greenhouse gas emissions from the supply of hydrogen via natural gas steam-methane reforming

[g CO_2 equivalent/MJ_{H2}]	France	Germany
Natural gas supply	18.3	18.4
Steam methane reforming	72.8	72.8
Total	**91.1**	**91.3**

The supply of hydrogen from natural gas steam methane reforming leads to about 91 g CO_2 equivalent per MJ of hydrogen based on the lower heating value. The greenhouse gas emissions from the supply of hydrogen via water electrolysis using electricity from renewable energy source are zero.

The electricity requirement for hydrogen production via water electrolysis decreases from 1.733 MJ per MJ of hydrogen based on the lower heating value today to 1.538 MJ per MJ of hydrogen in 2020 and afterwards. Since the energy use from construction of wind and photovoltaic power stations, electrolysers and vehicles have not been taken into account the GHG emission from renewable hydrogen production is zero.

Table 15: Greenhouse gas emissions from the supply of hydrogen via water electrolysis with renewable power (wind, PV)

[g CO2 equivalent/MJH2]	France	Germany
Renewable electricity	0	0
Hydrogen production	0	0
Total	**0**	**0**

The introduction of renewable hydrogen in the refinery decreases the greenhouse gas emissions from crude oil refining. For the calculation of the impact of renewable hydrogen, allocation by energy has been applied to allocate the greenhouse gas emission savings to the different products of the refinery. Refinery products such as gasoline, kerosene, and diesel have been considered for the allocation but not heavy products like heavy fuel oil (HFO) and bitumen.

Figure 26 shows the impact of the substitution of hydrogen from natural gas steam methane reforming by hydrogen from renewable electricity via water electrolysis. As reference the fossil fuel comparator indicated in ANNEX II of the Fuel Quality Directive [FQD 2015] has been used.

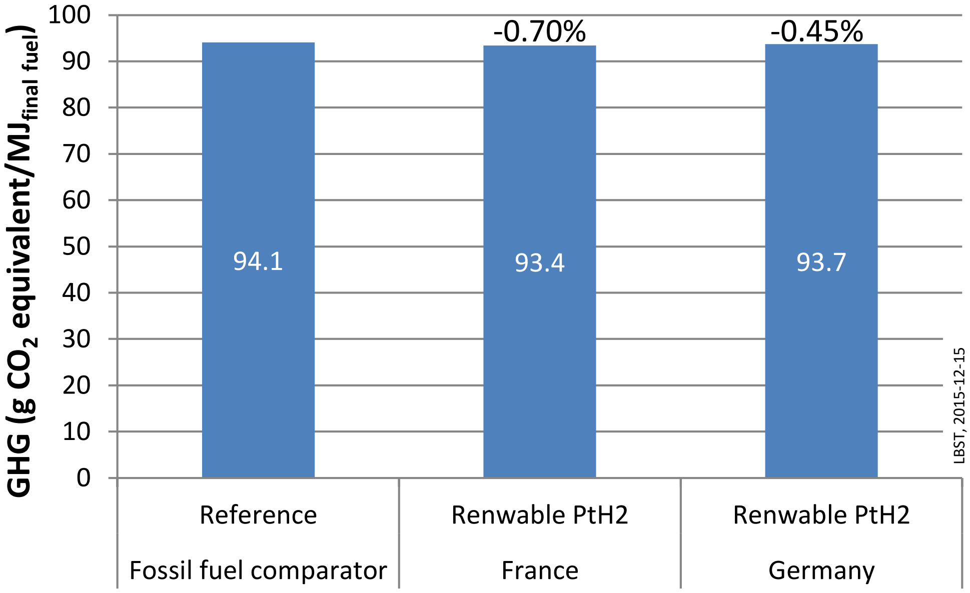


Figure 26: Comparison of greenhouse gas emissions from the supply of gasoline, kerosene, and diesel (source: LBST)

Compared to the fossil fuel comparator, the greenhouse emissions decrease by about 0.70% (France) or 0.45% (Germany) respectively. This represents about one tenth of the FQD's 6% greenhouse gas emission reduction required as a minimum for fuel supply by 2020.

It has been assumed that the electricity is derived from wind and photovoltaic power plants nearby the refinery site. Until 2030, the costs of electricity from a mix of 60% wind power (onshore) and 40% photovoltaic power based on the rated power decrease from today about 0.073 €/kWh to about 0.066 €/kWh (France) or 0.075 €/kWh to 0.068 €/kWh (Germany) respectively.

The specific investment has been calculated based on a progress ratio of 0.87 and a world market for electrolysis plants. Until 2025 the cost reduction for electrolysis plants decreases at about 45% from today about 1320 €/kW_e to about 730 €/kW_e in 2025 and about 550 €/kW_e in 2030. For the calculation of the cumulative investment in France and Germany until 2030 a logistic curve has been modelled for the installed capacity over time. Figure 27 shows the development of installed capacity for electrolysis plants at refineries.

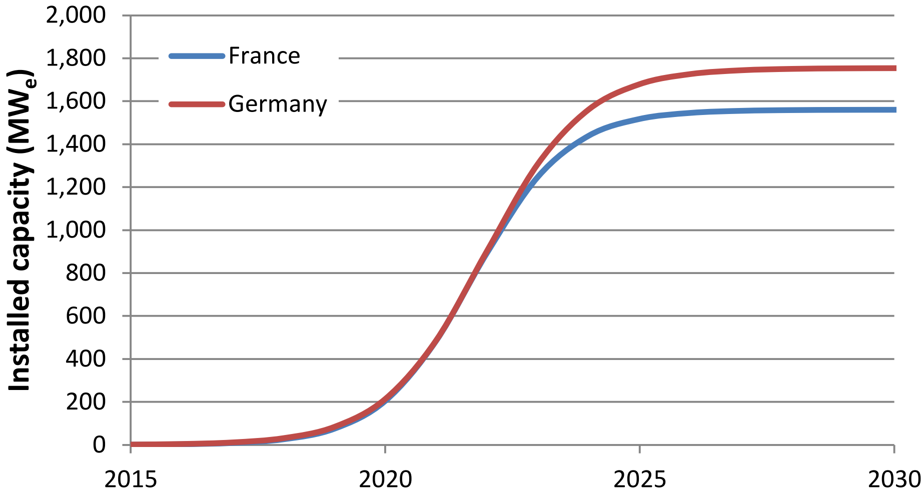


Figure 27: Development of the installed capacity of electrolysis plants in France and Germany (source: LBST)

Table 16 show the costs of hydrogen from renewable electricity. The hydrogen plant consists of the electrolysers, the hydrogen storage loading compressor, and the hydrogen storage.

Table 16: Costs of hydrogen supply from renewable electricity

	France (€/kg)		Germany (€/kg)	
	2015	**>2030**	**2015**	**>2030**
Electricity costs	4.24	3.42	4.39	3.54
Capital costs H2 plant	1.62	0.90	1.61	0.88
Maintenance H2 plant	1.26	0.73	1.26	0.72
Total	**7.13**	**5.05**	**7.26**	**5.14**

At a natural gas price of 0.03 € per kWh the costs for hydrogen from large scale natural gas steam methane reforming amount to about 1.4 € per kg of hydrogen which has been used as benchmark.

Figure 28 shows the cost of the supply of gasoline and diesel if hydrogen from natural gas steam methane reforming is substituted by hydrogen from renewable electricity.

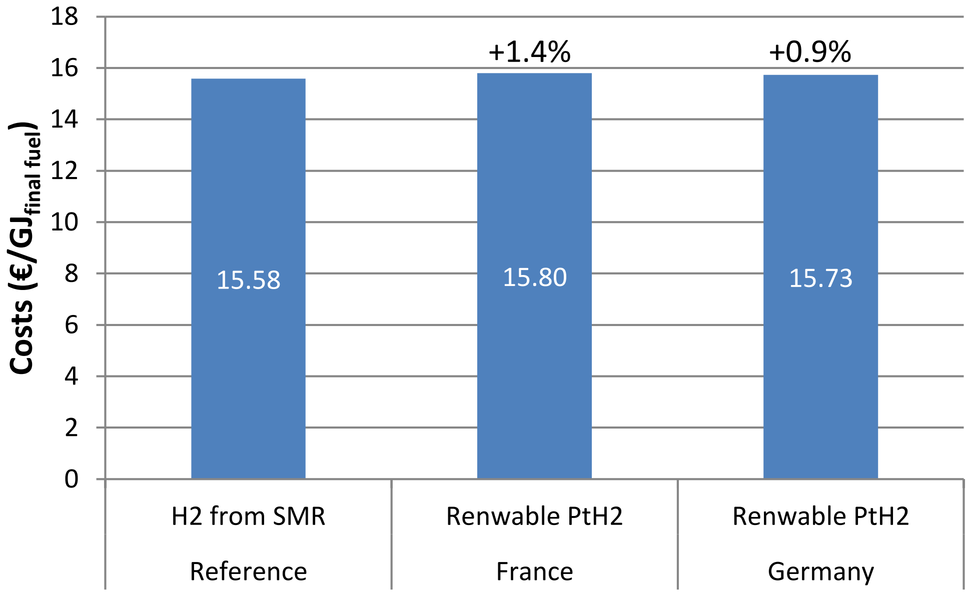


Figure 28: Comparison of the costs for the supply of gasoline and diesel (source: LBST)

The costs for the production of gasoline, kerosene, and diesel will increase by about 0.8 ct per litre Diesel-equivalents (1.4%, France) and 0.5 ct per litre Diesel-equivalents (0.9%, Germany) if hydrogen from natural gas steam methane reforming is substituted by hydrogen from renewable electricity. The greenhouse gas abatement costs amount to 331 (France) to 339 € (Germany) per t of CO_2 equivalent. The import price for gasoline and diesel indicated by [MWV 2015] has been used to calculate the price of the mix of gasoline and diesel.

If greenhouse emission reduction at refinery site could be applied to partly fulfil the EU Fuel Quality Directive less biofuel admixture would be required.

Further greenhouse gas emissions reduction can be achieved 'upstream' the refinery, i.e. by the reduction of flaring and venting at the oil fields and export of the associated gases, e.g. as liquefied natural gas (LNG) or gas-to-liquids (GTL). The use of hydrogen from renewable electricity in fuel cell vehicles (FCEV) can substitute gasoline and diesel vehicles and save greenhouse gas emissions from gasoline and diesel supply and combustion. The production of synthetic gasoline and diesel from hydrogen from renewable electricity (power-to-liquids) can substitute crude oil based gasoline and diesel leading to specific high greenhouse gas emission reduction down to approximately zero. A part of the refinery processes (distillation, hydrocracking) can still be used as components of the power-to-liquids plant.

Scenarios for greenhouse gas mitigation, associated electricity demands and cumulated investments

In the following, the greenhouse gas mitigation potential, electricity demands and cumulated investments are calculated as sensitivities from the bandwidth of net hydrogen demand in refineries in France and Germany substituted with hydrogen produced from renewable electricity sources. As renewable electricity sources, photovoltaics and wind power are assumed on a 40/60 basis (by installed capacities).

For this study, we calculate with onshore wind as a conservative assumption with regard to siting/accessibility aspects and annual equivalent full load hours.

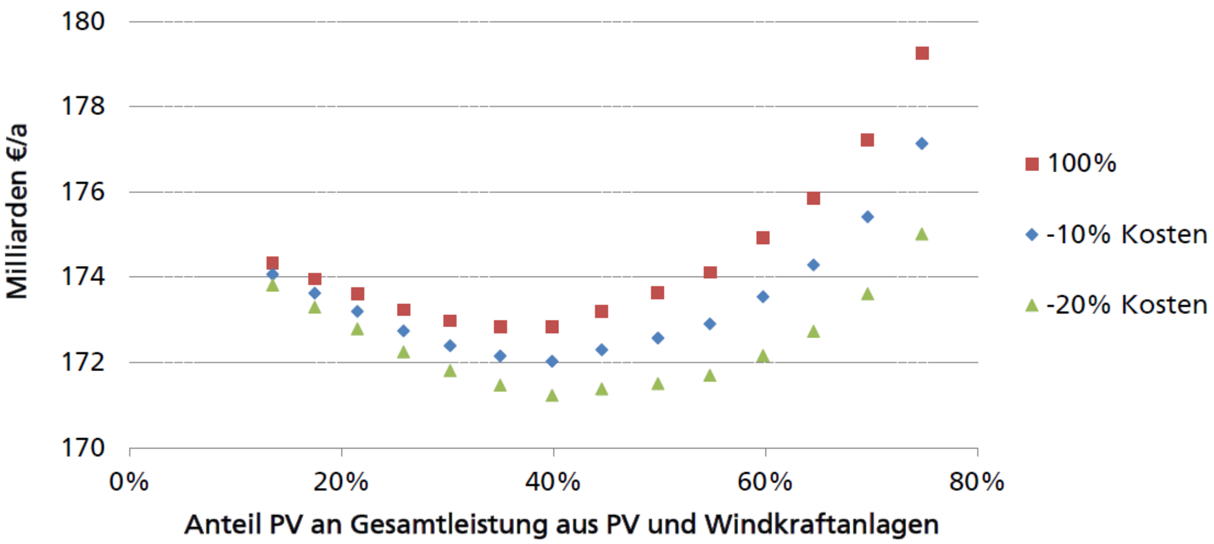


Figure 29: Sensitivity analysis of annual electricity systems full costs (y-axis) with variable PV share (x-axis) and variable PV costs (red = baseline, blue = -10% PV costs, green = -20% PV costs) [ISE 2013, p 31]

To give the 40/60 assumption some foundation, above-captioned Figure 29 shows that a 40% share of installed PV capacities in a PV and wind power generation mix result in somewhat minimum system full costs. The reason is that wind and PV electricity are most complementary to each other at this ratio leading to minimum storage requirement. However, the minima are quite flat, meaning that in practice also 30/70 or 50/50 mixes will give robust low system costs compared to PV dominant or wind dominant deployments scenarios. This strain of analyses has been taken on board in France, too, notable in [ADEME 2015].

The specific greenhouse gas emissions for per MJ of crude oil indicated in [Exergia et al 2015] have been multiplied with the annual amount of crude oil throughput in energy terms. The GHG emissions from crude oil refining amounts to about 4.3 MJ per MJ of crude oil in France and to about 5.0 g per MJ of crude oil in Germany. The lower heating value (LHV) of crude oil is assumed to be 42.6 MJ per kg. The equivalent full load period amounted to about 6600 hours per year in France [CPDP 2015]. For Germany it has been assumed that the equivalent full load period amounts to about 8300 hours per year as indicated in [FZJ 1994].

Table 17 gives the results for France and Germany for a scenario where all hydrogen from SMR is substituted by hydrogen from renewable electricity.

Table 17: Scenario results for hydrogen use in refineries in France and Germany (source: LBST)

	40 % PV : 60 % wind onshore	
	France	Germany
Net H_2 input per crude oil input	0.66 % (LHV)	0.39 % (LHV)
GHG mitigation of refinery emissions	1.33 Mt CO_{2eq}/a	1.50 Mt CO_{2eq}/a
	14.1 %	7.2 %
H_2 demand	4.06 TWh_{H2}/a 122 kt_{H2}/a	4.56 TWh_{H2}/a 137 kt_{H2}/a
Required electrolyser capacities	1.58 GW_e	1.78 GW_e
Electrolyser cost reduction 2025	45 $\%_{2015}$	45 $\%_{2015}$
Cumulated investments electrolysis [€]	1.5 billion €	1.6 billion €
Electricity demand H_2 production	6.24 TWh_e/a	7.02 TWh_e/a
Required RES plant capacities ▪ Wind onshore ▪ Photovoltaics	3.14 GW_e ▪ 1.90 GW_e ▪ 1.24 GW_e	3.73 GW_e ▪ 2.24 GW_e ▪ 1.49 GW_e
Cumulated investments RES plants	4.4 billion €	5.4 billion €

About 1.33 million t of CO_2 emissions could be avoided in **France** if hydrogen from natural gas steam reforming at refineries were substituted by hydrogen from water electrolysis using renewable electricity. This can be compared with the CO_2 emissions of passenger vehicles. If the real world (not NEDC) gasoline consumption of a typical C segment (e.g. Renault Mégane, VW Golf) passenger car is assumed to be 7 l of gasoline per 100 km and the annual mileage is assumed to be 14,000 km per year, about 2.31 t of CO_2 per vehicle and year will be emitted ('tank-to-wheel')[14]. As a result, the GHG emission savings from the substitution of hydrogen from natural gas steam methane reforming would be the same as the tailpipe CO_2 emissions of about 575,000 passenger cars. In case of a diesel fuelled C segment passenger vehicle with a real world fuel consumption of about of 5.5 l of diesel equivalent the GHG emission savings would be equivalent to 658,000 passenger cars in France[15].

About 1.50 million t of CO_2 emissions could be avoided in **Germany** if hydrogen from natural gas steam reforming at refineries were substituted by hydrogen from water electrolysis using renewable electricity. As a result, in Germany the GHG savings would be the same as the removal of about 648,000 of gasoline fuelled C segment passenger vehicles or about 740,000 of diesel fuelled C segment passenger vehicles from the road.

Table 18 gives a summary overview over avoided greenhouse gas emission equivalents in terms of C segment vehicles, differentiated by consumption (gasoline, diesel) and location (France, Germany).

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[14] Gasoline: LHV = 43.2 MJ/kg; density = 0.745 MJ/l; combustion: 73.3 g CO_2/MJ [JEC 2014]

[15] Diesel: LHV = 43.13 MJ/kg; density = 0.832 kg/l; combustion: 73.2 g CO_2/MJ [JEC 2014]

Table 18: Avoided refinery GHG emissions expressed in passenger car uses per year

Segment	Consumption	France	Germany
Numbers of 'C segment' cars (Renault Mégane, VW Golf, …)	Gasoline car @7.0 l/100km	575,000	648,000
	Diesel car @5.5 l/100km	658,000	740,000

The supply of green hydrogen to cover the net hydrogen demand in refineries reduces refiners 'gate-to-gate' emissions by 14.1 % in France and 7.2 % in Germany respectively. Introducing green hydrogen in refineries is thus a tangible action also with regard to corporate social responsibility (CSR).

The investment for the electrolysis plant includes hydrogen storage which consists of underground storage tubes (operated between 0.7 and 10 MPa) and a compressor for loading of the hydrogen storage. Underground storage tubes are not location specific as compared to e.g. hydrogen storage in underground salt caverns for which suitable formations have to be available. With regard to the economics, underground storage tubes are a conservative assumption.

The cumulated investments in renewable power and hydrogen production plants needed to provide 100 % green hydrogen to cover the net hydrogen demand from French and German refineries are 5.9 billion € and 7.0 billion €, respectively. While the absolute investment volumes may sound excessive at first, they have to be put into context. For example, in order to achieve the same annual greenhouse gas emission reduction with electric vehicles (BEV, FCEV), some 19.5 billion € is needed (650,000 electric vehicles · 30 k€/vehicle).

The use of green hydrogen in refineries corresponds to specific greenhouse gas mitigation costs of 331 €/t CO_{2eq} and 339 €/t CO_{2eq} in the France and Germany, respectively. This is significantly below the German penalty of 470 €/t CO_{2eq} which is due in case of non-compliance with the Federal Immission Protection Law (BImSchG). Greenhouse gas mitigation costs are generally high in the transport sector. Figure 30 gives an overview over a wide portfolio of power-to-transportation fuels.

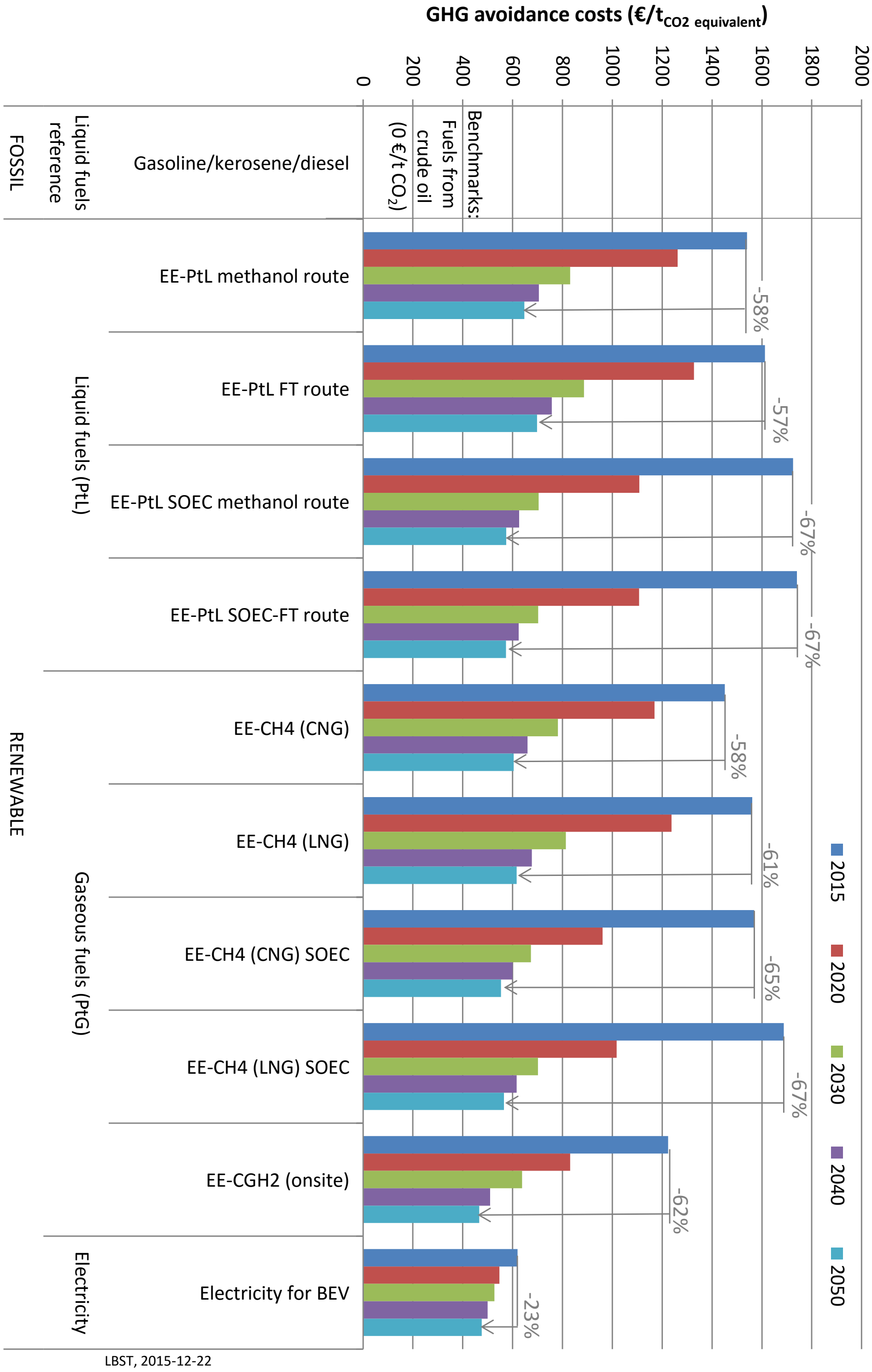

Figure 30: Greenhouse gas mitigation costs of renewable fuels from non-biogenic sources (full cost assessment 'well-to-tank' Germany) [LBST 2015]

From Figure 30 it can be seen that greenhouse gas mitigation costs of fuels from renewable electricity sources are in the range of 600 to 1700 €/t CO_{2eq} in the short to medium-term. Even long-term, fuel specific GHG mitigation costs are not expected to drop below 400 €/t CO_{2eq}.

Technology development of low-temperature electrolysis has been brought to a maturity level from which further cost reductions cannot be achieved with research and development efforts only. The further reduction of specific investments for electrolysers will require capacity deployments. No cost reductions are expected if no or only a few electrolysis plants are being deployed.

3.1.4 Renewable electricity potentials

France

The technical production potential from renewable electricity sources in France is derived from a meta-analysis of available studies, and complemented with own calculations. Figure 31 and Table 19 give the bandwidth of technical renewable electricity generation potentials found for France, depicted by power source.

Technically, there are vast renewable electricity generation potential from photovoltaics as well as onshore/offshore wind power in France.

Onshore wind energy can play a major role in achieving the renewable energy targets. The environmental and social constraints potential taken into consideration appear to have a limited impact on the wind energy potential. Nonetheless, for reasons of public acceptance, we assume a technical onshore wind potential of 374 TWh_e per year, which is close to the lower end of the bandwidth cited in study literature.

There are the five areas along the 5800 kms of coastline in France where offshore wind farms may be deployed: However, environmental constraints limit potential deployment. Indeed, there are noteworthy concerns addressed regarding the noise and visual impact of wind power, as well as the deaths of birds and bats that fly into rotor blades. The electricity generation potential for offshore wind power was assumed to be 270 TWh_e per year (including floating wind power plants) in this study.

Hydro power is the largest renewable source of electricity in France. Large hydro power is already highly developed – Dam deployment on French rivers are considered as having reached a maximum. France has major marine energy resources, however, this potential remains untapped because the technologies are still immature [GENI 2011]. Taking a conservative assumption, we include only the lower bandwidth of the technical electricity potentials from hydro power.

In this study, only a small share of the technical potential for geothermal power is assumed.

In Table 19 and Figure 31 an overview of the bandwidth and total technical potential for renewable electricity deployment is provided.

Table 19: Technical renewable electricity potentials in France (source: LBST based on [ADEME 2015], [EEA 2009], [IWES 2012], [ADEME 2014], [LBST 2015])

Technology	Long-term sustainable technical potential TWh_e/a			Renewable power production today** TWh_e/a
	Literature data		Assumptions for this study	
	Lower bandwidth	Upper bandwidth		
Hydro power*	119	222	119	63
Wind onshore	281	680	374	17
Wind offshore	200	820	270	0
Photovoltaics	299	466	382	6.4
Geothermal	0.2	1.2	0.7	0.083
TOTAL	899	2189	1146	86

* including marine energy (tidal and wave)
** data from [SOeS 2015] for 2014

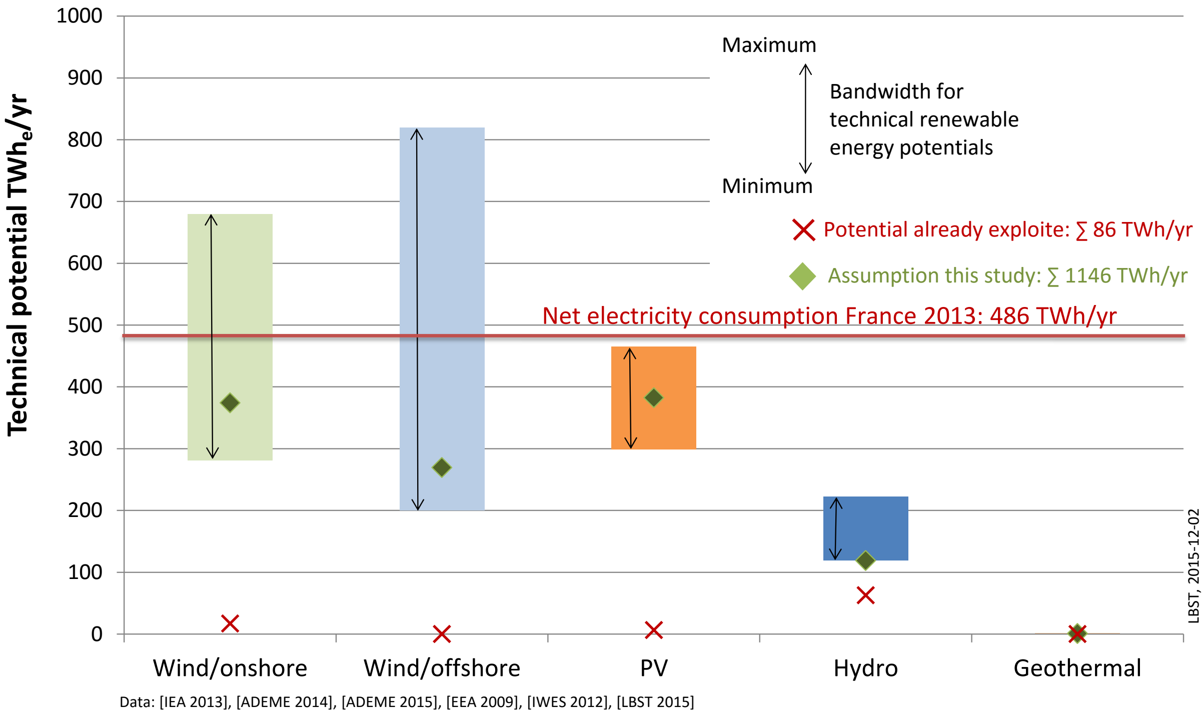

Figure 31: Technical renewable electricity potentials in France (source: LBST)

Based on [ADEME 2015] we come to the conclusion, that a conservative assumption for technical renewable electricity potentials in France is 1,146 TWh_e per year. To provide a comparative order of magnitude, in 2013 the net electricity consumption in France was 486 TWh_e, of which approximately17% from renewable energy sources. Technically, 100% electricity production from renewable energy in France seems possible. The future electricity demand will, amongst other factors, depend on what the transportation sector will require in terms of catenary lines, charging of battery-electric vehicles and not least for the production of power-to-fuels (PtH_2, $PtCH_4$, PtL).

In 2012, close to 6% of all agricultural land in use in France was dedicated to the production of biomass for bioenergy purposes [UFIP 2012].

Germany

The technical production potential from renewable electricity sources in Germany is derived from a literature meta study and complemented with calculations developed for the purpose of this study. The methodology and data are explained in more detail in [LBST 2015]. Table 20 and Figure 32 show the bandwidth of technical renewable electricity generation potentials found for Germany, depicted by renewable power source.

Table 20: Technical renewable electricity potentials in Germany (source: LBST)

Technolgy	Long-term sustainable technical potential TWh_e/a			Renewable power production today TWh_e/a
	Literature data		Assumptions for this study	
	Lower bandwidth	Upper bandwidth		
Hydro power	25	42	25	19.6
Wind onshore	195	2897	390	55.9
Wind offshore	64	300	200	1.4
Photovoltaics	309	471	390	36.1
Geothermal	15	300	15	0.03
TOTAL	608	4010	~1000	113

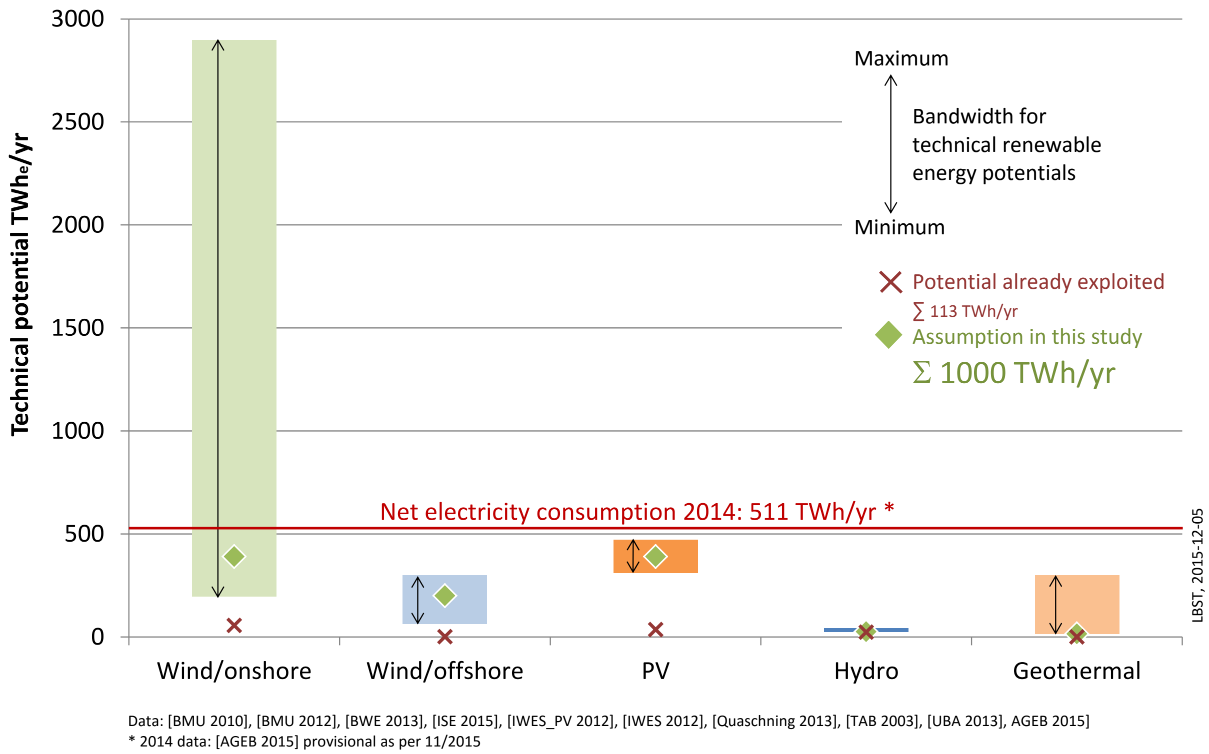

Figure 32: Technical renewable electricity potentials in Germany (source: LBST)

Technically, there are vast renewable electricity potentials from onshore wind power in Germany. For reasons of public acceptance, we assume a technical onshore wind potential of 390 TWh_e per year, which is close to the lower end of the bandwidth cited in study literature.

In this study, we include only a small share of the technical potentials from geothermal power. Most of geothermal heat potentials in Germany would require a stimulation process, i.e. hydraulic fracturing ('fracking') for heat extraction. There is no public acceptance for fracking in Germany.

Renewable electricity generation potential from photovoltaics could be significantly higher compared to what is shown in Figure 32. As a conservative assumption, we have not included PV, neither from brown nor green fields nor conversion areas.

We come to the conclusion, that a conservative number for technical renewable electricity potential in Germany is 1,000 TWh_e per year[16]. For the sake of comparison, in 2014 the net electricity consumption in Germany was 521 TWh_e [BDEW 2015]. Today, only about 11% of this renewable electricity potential is currently exploited in Germany.

Based upon the assessment of technical renewable electricity generation potentials in France and Germany, we can conclude that exploiting these potentials is more constrained by public acceptance for renewable power plants and balance of system installations (grid, storage) than by technical feasibility or cost.

[16] Assuming more progressive installation density and yield parameters could more than quadruple this figure and result in renewable electricity supply potentials of some 4,000 TWh_e/year in Germany.

Comparisons

For our 100 % green hydrogen scenario to cover the net hydrogen demand in French and German refineries, an annual renewable electricity supply of 6.24 TWh_e and 7.02 TWh_e respectively is needed. In 2014, some 86 and 113 TWh_e were produced from renewable source in France and Germany respectively. Both values have to be compared against the more than 1,000 TWh_e per year of technical renewable electricity generation potentials in France and Germany (see the previous section).

To give an example of the number of renewable power plants needed: in the French scenario early (2020) renewable electricity demand for the hydrogen supply of a single refinery is equivalent to the annual electricity production of eight 4 MW wind power plants and 20 MW of installed PV capacity. To supply the total net hydrogen refinery demand, which is assumed in the scenario by 2025, an equivalent of 584 MW wind power plants and 151 MW of installed PV capacity would be needed in average per refinery in France.

3.2 Discussion on green hydrogen for use in refineries

3.2.1 Conclusions

From the results of Application A 'Hydrogen from power-to-gas for use in refineries', the following conclusions can be drawn:

- Green H_2 in refineries is an attractive GHG mitigation option;
- A portfolio of options will be needed post-2020 at the latest;
- It would mean introduction of green H_2 in an established bulk H_2 application;
- Volume production of H_2 reduces electrolyser costs;
- Electrolysers 'valley of death' is bridged by all fuel users.

From a macro-economic perspective, the deployment of electrolysers for refineries is an energy-strategic move entailing long-term benefits for all hydrogen uses. Furthermore, it is a stepping stone for refiners into future power-to-liquids processing.

3.2.2 Recommendations

Based on the results and conclusions from the analysis of the potential role of green hydrogen in refineries, the study authors recommend to:

- Establish regulatory grounds for the accountability of green hydrogen in refineries at EU level;
- A fast-track implementation may however be rather given at national level because EU FQD had recently been updated;
- Green hydrogen sustainability criteria need to be defined and voted at EU and national level.

3.2.3 Fields for further research

For Application A full-cost analysis was chosen as the most appropriate method for a fair high-level comparison in order to explore the potentials from green hydrogen in refineries. Analytical next steps are, with a view to short-term implementation and hardware deployment:

- Refinery specific business case analyses;
- Regional renewable electricity supply scenarios;
- Synergies between electricity, refinery, H_2 infrastructure.

3.3 APPLICATION B: Semi-centralised power-to-hydrogen business cases

As explained in section 2, Power-to-gas provides an effective coupling mechanism between the electricity, transport and industrial sectors, providing new powerful ways to address intermittency and an abundant supply of storable low-carbon energy, especially to decarbonise transport.

The particular configuration analysed here is a semi-centralised power-to-gas system. Such a system is advantageous in that it can address multiple needs of a local energy system whilst producing economies of scale and avoiding high hydrogen transportation costs due to relatively short delivery distances.

The business case for such a system is analysed for various sets of hypotheses, regarding, for instance, the equipment costs, the electricity energy cost profile and grid charges, hydrogen market uptake, the existence of a feed-in-tariff for injection of hydrogen into the natural gas grid, etc.

3.3.1 The cost of the electricity

The cost of the electricity consumed by the electrolyser can be decomposed into (i) a purely energy based component corresponding to the cost per energy unit when electricity is purchased on the electricity market, and (ii) grid charges (assuming connection to the grid) along with the various applicable fees and taxes. These elements, which are -to a large extent- determined by the national context, are further described below for France and Germany.

As the energy-based cost component of electricity purchased on the spot market is time dependent, it is represented by a price distribution, containing all the prices observed in a year (over a 1-hour time span) ranked in ascending order, called, in this study, the price-duration curve.

To determine the business case at 2030 horizon, electricity price duration curves were created for France and Germany based upon two acknowledged capacity mix scenarios.

First, the methodology to model the electricity supply curves will be presented. Thereafter, the determinants of the price of electricity will be presented for France and Germany.

Methodology for modelling the electricity supply curve:

As the factors determining the price-duration are multiple and their evolution difficult to predict, it is not possible to realistically predict the price-duration curve at the 2030 horizon. Nonetheless, a cost curve based on the marginal cost of electricity production assuming utilisation of the projected generation capacity for the projected consumption profile based on merit order can be developed.

The expected electricity prices are based on a simplified modelling framework of the German and French electricity systems. First, the model calculates a step-wise linear merit-order curve (i.e. an increasing production costs curve) for each hour of the year by taking the marginal costs of each type of power plant into account (i.e. based on fuel costs, corresponding efficiency and CO_2 costs) and by assuming costs linearity between the different generation technologies[17]. For each hour of the year, the intersection between the merit-order curve and the residual demand (i.e. actual electricity demand less renewable feed-in[18] and less 'must-run' production[19]) represents the uniform market clearing price.

At this point, it is important to mention that for the sake of simplicity the model represents cost minimisation of a simple electricity system without any flexibility options such as demand side management or electricity storage. In reality, in the future the energy systems may be characterised by an increasing share of additional measures for system flexibility potentially influencing the actual electricity prices. However, until 2030, the increase in renewable energy generation is unlikely to be so important as to require a large-scale deployment of these flexibility options. Therefore, the impact of these options on the power market dynamics are not taken into account. In addition, the model assumes that the price mechanism based on marginal costs (i.e. so-called 'energy-only' market design) remains unchanged until 2030.

[17] In reality the merit-order curve is estimated by calculating the marginal costs of each generation unit representing a step function. However, for the sake of numerical tractability the underlying model is based on 7 generic power plants types and linear increase of marginal costs between two consecutive technologies.

[18] The model assumes that the marginal generation costs of fluctuating renewable power plants (such as wind and solar) are close to zero and have priority when satisfying the demand.

[19] 'Must-run' production is provided by specific power plants which are operated in the base-load mode in almost all hours of the year either for technological (e.g. such as geothermal or run-of river power plants) or economic reasons (i.e. due to ramp-up and ramp-down costs of rather inflexible units such as coal power plants).

France

Electricity price-duration curve

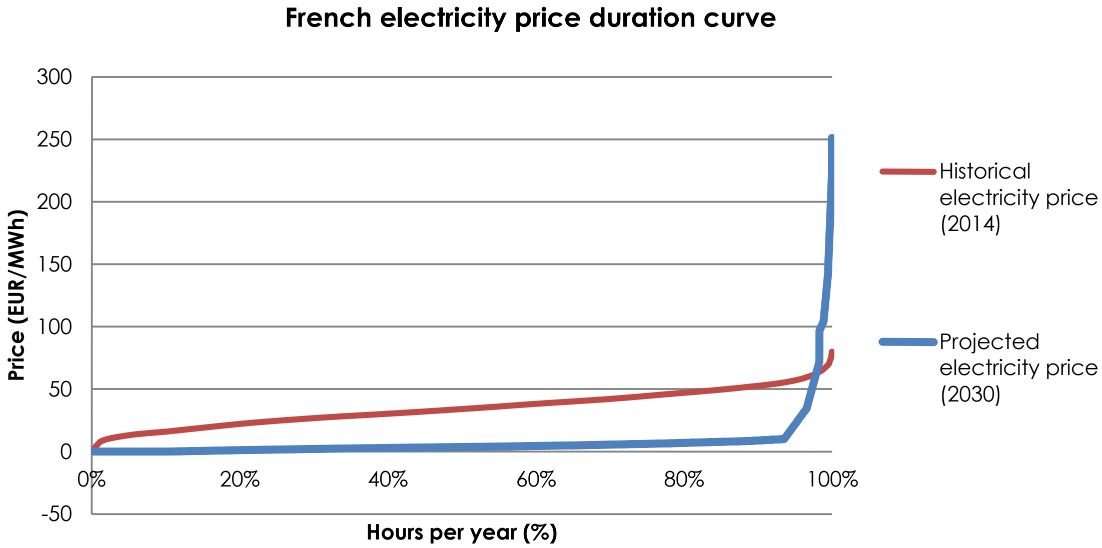

Figure 33: Historical and projected marginal-cost based price duration curves for France (source: Hinicio & LBST based on data from [RTE 2015b])

The figure above represents the two price load duration curves for France. The first is based on the European Power Exchange (EPEX) French day ahead spot price for 2014. The second price duration cover is modelled on the basis of RTE's Nouveau Mix[20] scenario using the aforementioned methodology.

The nouveau mix scenario is a widely accepted scenario developed by the French electricity network operator in its long-term market equilibrium projections. This scenario is the only scenario which achieves all the energy targets set in the Energy Transition law (LTE) enacted in 2015. The price of carbon of 95 €/ ton of carbon is also a hypothesis taken from the nouveau mix scenario and reflects current government policy. Fuel prices are taken from the 450 ppm World Energy Outlook (WEO) projections.

All of the modelling assumptions are summarised in tables 16 to 18. Furthermore, the estimated total energy consumption is 480 TWh.

[20] For a detailed description of the scenario please see: RTE, Bilan prévisionnel de l'équilibre offre-demande d'électricité en France, 2014 edition, pp. 160 to 174.

Table 21: Techno-economic data for different power plant types (maximal costs, i.e. for highest expected market prices and lowest efficiency) (source: [RTE 2015b])

Parameter	Unit	Hydro	Coal/ waste	CCGT**	Gas turbine	Nuclear	Tidal
Prices primary energy	€/MWh	0	37.8	22.68	37.8	10	0
Prices CO_2 certificates	€/t_{CO2}	95	95	95	95	95	95
Efficiency (LHV*)	%	100%	46%	58%	39%	40%	100%

* LHV = Lower heating value. ** CCGT = Combined cycle gas turbine

Table 22: Dispatchable capacities available in 2020 and 2030 (source: [RTE 2015b])

Parameter	Unit	Nuclear	Hydro	Coal/ waste	CCGT	Gas turbine
Capacity 2030	GW	37.6*	4.92*	1.8	9.4**	11.4

* 100% of installed capacity is must-run. ** 25% thereof is must-run.

Table 23: Renewable power generation in 2020 and 2030 (source: [RTE 2015b])

Parameter	Unit	Wind onshore	Wind offshore	PV
Generation 2030	GWh	62,441	9,934	27,445

The results for 2030 imply a price of electricity close to zero for beyond 8000 hours a year which can be explained by the combination of nuclear and variable renewable energy production which have a short-term marginal cost of electricity production close to zero.

This estimated price duration curve represents an extreme scenario based upon the merit order for the nouveau mix scenario. At best, it represents the electricity prices on the spot market at the 2030 horizon which provides only a limited picture of electricity prices as currently over two thirds of production is contracted. The nouveau mix scenario assumes important energy efficiency measures and requires the deployment of demand response measures which the model does not account for. Because the results for the 2030 price duration curve are not considered as reflecting a likely electricity price projection, it was not used for evaluating the power-to-hydrogen business case in the 2030 horizon.

Grid fees and Taxes

To provide the reader with an understanding as to how grid fees and taxes were determined for the business case evaluation, the following section will focus on the main components of the grid electricity tariff and taxes and how they apply to the semi-centralised power-to-hydrogen system. First the main elements setting the electricity grid tariff will be presented. Second, the various taxes on energy consumption will be presented. Lastly, the électro-intensif statuses and their application to the semi-centralised power-to-hydrogen system will be discussed. At each intermediary step, the impact on the cost structure for the electrolyser will be presented.

As mentioned earlier, the grid use fee is set so as to cover the running and investment costs of the national and regional electricity network operator. It is, composed of 3 components: the amount of electricity withdrawn from the grid (hereafter withdrawal), client management fees and the metering. the annual withdrawal component covers the majority of the TURPE's cost. On top of these costs, the TURPE can include addendums for services the grid operator provides on demand (such as emergency back-up power).

The subscribed power was assumed to be 2,000 kW and energy consumption was set at 8,000 MWh. On that basis the TURPE total annual costs for the electrolyser would be as follows:

Table 24: TURPE total annual cost breakdown for a 2,000 kW subscription and an 8,000 MWh consumption (source: Hinicio, based upon [ERDF 2015])

TURPE component	Corresponding tariff (k€/year)
Annual withdrawal component without temporal differentiation –fixed cost	42,8
Annual withdrawal component without temporal differentiation –variable cost	100,3
Total annual TURPE cost	**143,9**

Since the electrolyser is assumed run 8 000 hours a year, on a per MWh basis, the TURPE is 17.99 €.

As presented in section 2.2.4. c), in France, there are 4 main electricity taxes: the CSPE, the CTA, the TCFE and VAT. Since companies are exonerated from paying VAT on electricity, VAT was not taken into account. In 2015, the TCFE amount was 0.5 €/MWh. The CTA corresponds to 10.14% of the TURPE in 2015. The amount of the CSPE varies as it covers, retroactively, the electricity providers' costs for purchasing renewable electricity, social tariffs and selling electricity at the same price in non-interconnected areas as in mainland France. In 2015, the CSPE was set at 19.5 €/ MWh.

However, with the électro-intensif statuses, both taxes on electricity consumption (CSPE/ TICFE) and the tariff for the use of the electricity network (TURPE) are partially exonerated.

The energy intensive status has been in place in France since 2010, although its legal status is only currently being set. As a result, the fiscal and tariff reductions it was granted varied over time and were largely dependent on circumstances.

The électro-intensif status was defined following the creation of a legal exception for the provision of electricity via a long-term contract granted to a consortium of companies named Exeltium. In 2005, Exeltium, a consortium of 26 industrial actors was exceptionally granted the right to purchase electricity on a 25-year contract. At the time, the consortium was not granted any tax reductions although it was a source of political debate. However, this event set a definition of the électro-intensif. Companies with an electricity consumption of 2.5 kWh per euro of added value were considered électro-intensif.

In 2014, the Commission for the Regulation of Energy (CRE) which is in charge of controlling energy markets, granted électro-intensif companies a retro-active 50% reduction on the TURPE because revenues from the TURPE for the previous year exceeded costs. The surplus was passed on to electro-intensive companies to improve their economic competitiveness. This exemption from the electricity grid fee was the first case where the électro-intensif status was associated with an exoneration.

Currently, within the context of the LTE, the status of électro-intensif will be legally defined. Although status' characteristics are, as yet, not settled, the main elements associated to these new statuses are as follows. Two statuses have been proposed: one for électro-intensif companies and another for hyperélectro-intensif companies. The eligibility criteria associated with these statues will follow the past criteria, namely a given level of electricity consumption for each euro of added value but will further require companies to commit to reducing their energy intensity. Depending on the company's energy intensity, partial grid fee and energy taxes will be provided.

More specifically, companies or sites with an annual consumption of more than 7 GWh per year and for which the TICFE is equal to at least 0.5% of their added value may be granted this status. The reduction rate varies depending on the amount of electricity consumed per unit of added value as follows:

Table 25: CSPE reduction rate depending on energy intensity per unit of added valie for électro-intensif companies (source: Article 266 quinquies C du Code des Douanes)[21]

Electricity consumption per unit of added value (kWh/€)	CSPE amount (€/ MWh
Less than 3 kWh	1
Between 1.5 kWh and 3 kWh	2.5
Less than 1.5 kWh	5.5

Furthermore, companies for which electricity consumption is more than 6 kWh/€ of value added and with a strong exposed carbon leakage[22] risks because of international competition, the may be granted the hyperélectro-intensif status. In this case, the level of CSPE is 0.5 €/ MWh.

In the case of the electrolyser, electricity represents more than 6 kWh/€ value added. In the reference scenario, the electrolyser is assumed to run 8,000 hours. The electrolyser therefore fulfils the first hyperélectro-intensif eligibility criteria. However, hydrogen production is not subject to international competition; carbon leakage is not an issue. Nevertheless, for the purpose of evaluating the business case of power-to-hydrogen, it was assumed that the project could, considering its innovative nature and conditional upon negotiations with the CRE, benefit from the hyper electro-intensive status.

To provide a comparative vision of the advantages linked to the hyperélectro-intensif status, all energy taxes and the grid tariff are presented below on a per MWh basis assuming a 2,000 kW capacity and 8 GWh consumption per year:

[21]http://www.legifrance.gouv.fr/affichCodeArticle.do?idArticle=LEGIARTI000023216102&cidTexte=LEGITEXT000006071570&dateTexte=vig

[22] As defined by the European Commission. See: C(2009 10251: Commission Decision of 24 December 2009 determining, pursuant to Directive 2003/97/EC of the European Parliament and of the Council, a list of sectors and subsectors which are deemed to be exposed to a significant risk of carbon leakage.

Table 26: Summary of French energy taxes, fees and tariffs as applied to the electrolyser in the reference scenario (source: Hinicio)

Name of the energy tax or grid tariff	Price without hyperélectro-intensif status (€/MWh)	Prices supposing hyperélectro-intensif status (€/MWh)	Prices which informed the reference business case
TURPE	17.99	1.8	17.99
CSPE/TICFE	19.50	0.50	0.50
CTA	1.80	.18	1.80
Total	39.20	2.40	22.30

Without tax and grid reductions, total energy consumption taxes were estimated at 39.2 €/MWh. With the hyperélectro-intensif status, total energy taxes and grid access would be 2.4 €/MWh.

Within the initial business case for the semi-centralised power-to-hydrogen system, we assumed that the electrolyser would benefit from the hyperélectro-intensif regime. Total energy taxes and grid tariffs for the reference scenario were thus 22.3 €/MWh.

It was further assumed that electricity consumed to produce hydrogen which would be injected into the natural gas grid to provide would be exonerated from the TURPE.

Germany

Electricity price-duration curve

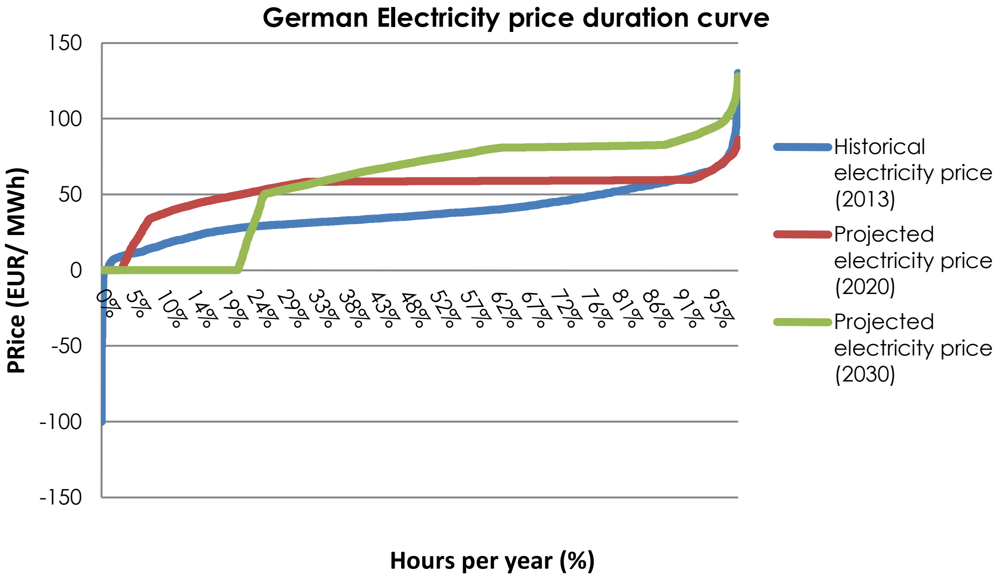

Figure 34: Historical and projected marginal cost-based price duration curves Germany (source: LBST based on data from [Nitsch et al., 2010])

The figure above portrays electricity price duration curves for Germany for the years 2013, 2020 and 2030. The 2013 price duration curve is based the observed prices in 2013. The price duration curves for 2020 and 2030 were derived using the methodology presented in subsection a).

For the projected price duration curves, the techno-economic assumptions for different power generation technologies were derived from [Nitsch et al. 2010a] and [Nitsch et al. 2010b]. The fundamental assumptions on the system design (available dispatchable capacities, actual electricity demand, renewable generation as well as expected prices for fossil fuels and CO_2 certificates) are based on Scenario A[23] of the German "Leitstudie", a widely accepted study on the future energy system in Germany conducted for the German Federal Ministry for the Environment (see [Nitsch et al. 2012a] and [Nitsch et al. 2012b]). The generic demand and renewable feed-in profiles are based on publically available historical data from 2012 provided by [ENTSO-E 2013] and German transmission system operators.

All assumptions are summarised in Table 27 through Table 29. Furthermore, the expected overall electricity demand in 2030 is 564 TWh in 2020 and 549 TWh.

[23] The interested reader is referred to [Pregger et al. 2013] for a detailed definition of scenario A.

Table 27: Techno-economic data for different power plant types (maximal costs, i.e. for highest expected market prices and lowest efficiency)

Parameter	Unit	Geo-thermal	Hydro	Lignite	Coal/ waste	CCGT**	Biogas	Gas turbine
Prices primary energy	€/MWh	0	0	4.82	17.64	29.16	29.16	29.16
Prices CO_2 certificates	€/t_{CO2}	27	27	27	27	27	27	27
Efficiency (LHV*)	%	100%	100%	43%	46%	58%	39%	40%

* LHV = Lower heating value. ** CCGT = Combined cycle gas turbine

Table 28: Dispatchable capacities available in 2020 and 2030

Parameter	Unit	Geo-thermal	Hydro	Lignite	Coal/ waste	CCGT	Biogas	Gas turbine
Capacity 2020	GW	0.30*	4.70*	13.26**	21.11***	27.66	8.43	9.22
Capacity 2030	GW	1.00*	4.92*	6.37**	28.82	15.00***	10.13	9.61

* 100% of installed capacity is must-run. ** 50% thereof must-run. *** 25% thereof is must-run.

Table 29: Renewable power generation in 2020 and 2030

Parameter	Unit	Wind onshore	Wind offshore	PV
Generation 2020	GWh	82,355	33,152	45,366
Generation 2030	GWh	108,262	96,130	59,417

Grid fees and Taxes

An introduction to German electricity sector's regulatory framework is given in the introductory chapter.

For Germany, basically, two different sets of grid fees and taxes apply depending on the legal setup (power contract) and physical setup (with or without grid connection) of the business case. The first case is purchase on the electricity market with a connection to the public grid. The second case is typical for direct power contracts, i.e. electricity supplied from dedicated renewable production facilities, here assumed to be without the use of the public electricity grid (a few kilometres long electricity line between power production and consumption may be included, provided that it is project-dedicated and not connected to the public electricity grid).

In the following, the possible cost components associated to either case are briefly introduced and conditions for their (non-)applicability described.

If there is no public grid used for electricity delivery AND if both supply and demand-side are the same operating entities, THEN PtG electricity consumption is exempted from Renewable Energy Sources Act **(EEG) appropriation** according to EEG appropriation EEG 2014 § 61 (22) N° 2 and N°3.

According to the Energy Industry Act (EnWG) §118 (6), all electricity storage plants that (i) are newly built after December 2008 and (ii) that started operation from August 2011 (iii) within 15 years are exempted from **grid fees** for 20 years from the operation start date onwards. This exemption applies to water electrolysis in power-to-gas plants under the consideration of EnWG §118 (6) sentence 7.

There are currently no exemptions from **CHP appropriation** (KWK-Umlage), **offshore wind appropriation** (Offshore-Umlage) and **grid appropriation** (Stromnetzentgelt-verordnung – StromNEV) – they are fully applicable. However, the regulatory ground hereto is not 100 % settled. Wheter §118 Abs. 6 may allow an exemption from certain grid fees which support CHP appropriation, offshore wind appropriation, or the grid appropriation is currently being discussed.

Power-to-gas plants are regularly fully exempted from **electricity tax** based on StromStG §9a sentence 1.

In the case of own production/consumption, public grids are typically not used. Operators of power-to-gas plants are thus freed from **concession fees**. In the case of a power line connecting the supply and demand side and crossing public grounds, concession fees have to be negotiated with the relevant community. In the case where the public electricity grid is used, concession fees apply.

With regards to the applicability of CHP appropriation, offshore wind appropriation, and electricity grid appropriation, the key indicator is the connection to the public grid. If the power-to-gas operator is not using public grids, there is no obligation to pay the aforementioned appropriations.

As a summary, Table 30 gives an overview of applicable electricity price components/exemptions for power-to-gas systems. The situation for the year 2016 is depicted based on the latest regulatory changes. The following PtG plant parameters were assumed: 1 MW installed nominal PEM electrolyser (2 MW peak) with an electricity consumption of 7 GWh per year.

Table 30: Price components for PtG system including exemptions in 2016 as per November 2015 (Source: netztransparenz.de)

Case	Electricity purchased on the market			Electricity supplied from dedicated renewable production facility (without use of public electricity grid)
Plant size	1 MW nominal (2 MW peak)			1 MW nominal (2 MW peak)
Price unit	ct/kWh			ct/kWh
Electricity price	X			–
EEG appropriation	6.354			2.22[24]
Network use fees	0			0
Consumer group	A' [25]	B' [26]	C' [27]	–
KWK (CHP) appropriation	0.445	0.040	0.030	0
Offshore wind appropriation	0.040	0.027	0.025	0
StromNEV §19 appropriation	0.378	0.05	0.025	0
Concession fee	0.11			0
Electricity tax	0			2.22
Total 2016	**X + 7.3 for the first 1 GWh, then X + 6.6**			**2.22**

3.3.2 Feed-in tariffs (FiT)

In the context of power-to-gas, hydrogen injected into the natural gas grid may benefit from a feed-in tariff.

France

Until very recently, the support mechanism for the production of renewable energy in France was a Feed-in-tariff combined with grid-priority. Currently, the implementation

[24] As defined in EEG 2014 §61 (2) N°2 and N°3.

[25] Consumer group A': Applicable for the first 1 GWh of electricity consumed per connection point.

[26] Consumer group B': Applicable for the electricity consumed above 1 GWh per connection point.

[27] Consumer group C': Applicable for end consumers whose annual consumption is >1 GWh AND whose electricity bill is >4 % of the turnover in the preceding year ('energy intensive').

of the European Directive on State aid is modifying the renewable energy support mechanisms. As renewable energy penetration increases in the electricity market and the cost of producing renewable electricity decreases, renewable energy is progressively subjected to market conditions. To encourage intermittent renewable energy producers to manage their production according to market conditions, the new mechanism will be an ex-post premium complementing the market price. Energy providers will no longer have the obligation to purchase all the energy produced via renewable technologies. At first, the modification of the support modalities for the production of renewable energy will only concern large installations (more than 500 kW). Progressively, this new mechanism is set to replace the existing FIT mechanism. However, some installations and technologies, such as onshore wind, will continue to receive economic support via the FiT. The decrees specifying which technologies continue to receive the FiT remain to be published. Nonetheless, support for immature renewable energy technologies will continue to be a FiT.

In 2011, France introduced a FiT for the injection renewable gas (namely biomethane) into the natural gas grid. The injection of biomethane from agricultural, household or food production as well as the processing of industry waste into the natural gas grid is remunerated via a feed-in tariff of between 45 and 125 €/MWh, varying depending on the installation's capacity and the type of waste used for biomethane production. This FiT price is guaranteed for 15 years.

Germany

A key component for the development of renewable electricity production in Germany is the **Federal EEG (Renewable Energy Law)**:

- A preferential up-take of electricity from renewable sources in the grid is granted.
- Fixed – but regularly updated – feed-in tariffs (FiT)guaranteed for 20 years for a wide range of renewable power plants (solar, wind, hydro, geothermal, biomass, CHP); competitive tendering is increasingly being trialled for larger renewable power plant installations.
- All FiT-remunerated renewable electricity is sold on the spot market. The green attribute hereby becomes 'grey' in order to avoid double-counting; direct marketing is increasingly being introduced.

Currently, there are some development lines that may eventually render the EEG superfluous in the future:

- Recently, the FiT reduction has been coupled with a 'deployment corridor' that states an annual minimum and maximum capacity for new installations. Even renewable power plants that are realised outside the FiT scheme (and connected to the electricity grid) count towards the corridor.
- With regard to electricity from biogas, the FiT tariff was increased a couple of years ago as biogas feedstock prices had been rising. For the last two years, the number of newly-deployed biogas plants has significantly decreased. LBST considers the market for maize-fed biogas plants to be mature. Waste feedstocks require higher FiT and are thus not attractive at current FiT levels. Today, the vast majority of biogas power plants still generate and feed electricity into the grid in a base-load manner. Only recently, an additional FiT supplement has been implemented for more flexible (i.e. electricity demand

oriented) feed-in of electricity generation from biogas as additional heat storage and/or power production capacities are needed. Financing storage and flexibility of electricity from biogas is in fact closer to a capacity mechanism.

- While in the past most of the installed renewable power plants in the FiT scheme have been built by individuals, associations, and small investors, the Federal Ministry for the Economics – the legislative body responsible for the EEG law – is successively replacing FiT schemes by via several alternatives such as direct marketing and project auctioning.
- Most importantly, renewable power technologies are successively breaking-even with average electricity prices that private individuals and companies are paying. Wind onshore and PV are already lower-cost alternatives than newly-built fossil and nuclear power plants (including lignite if carbon capture and storage is assumed for a level-playing comparison).

3.3.3 Semi-centralised power-to-hydrogen business model description

This section aims to provide the reader with a clear picture of the power-to-hydrogen business model in three dimensions: components of the value chain, how the system is dimensioned and what the cost structure for each component of the system is.

The structure of the following section is broken down into three parts. First the dimensioning of the production is explained and its associated costs are presented. Thereafter, the logic underpinning the dimensioning of the transport and storage element is detailed and its costs presented. The business case for the semi-centralised power-to-Hydrogen is largely dependent upon the cost of electricity which largely determines the cost of hydrogen. This section will therefore conclude with a focus on the hypotheses developed to evaluate this cost by presenting the price duration curves which are taken into consideration and the fiscal regime for end-consumers in France and Germany. Each of these sections, representing a segment of the value chain, are divided into 3 subsections: capital investment costs (or CAPEX), operation and maintenance costs (or OPEX) and revenues.

Main components of a semi-centralised power-to-hydrogen system

The semi-centralised power-to-hydrogen system covers the hydrogen production and supply. Hydrogen is produced via a PEM electrolyser. Following production, the hydrogen is compressed to 200 bar using a compression skid. An injection skid is added to the hydrogen production site if the hydrogen is injected into the natural gas grid. Once compressed, the hydrogen is stored in tube trailers which are transported from the production site to the hydrogen refuelling stations. Of the latter, only the storage system into which the hydrogen is delivered is considered to be part of the power-to-hydrogen system.

Hydrogen production requires investments in an electrolyser, a compression and an injection skid as well as storage. Transport and supply of the hydrogen, requires investment in tube trailers and storage systems for receiving and storing the product at the point of use. Transport operations are assumed to be outsourced to a transport company providing the means of transports (i.e. trailers).

Revenues from hydrogen sales are redistributed along the value chain based upon an initial hypothesis of the price at which the kilogram of hydrogen for mobility is sold to hydrogen refuelling stations. To model the business case for the system, capital investment cost per unit capacity and running costs were associated to each component of the value chain (the electrolyser, the compression skid, the injection skid, transport and storage). The first step consists in dimensioning the hydrogen production and distribution system. Then, on the basis of technology unitary prices, investment and operational costs were calculated.

Figure 35 presents the different components of the semi-centralised power-to-hydrogen system with their associated cost structure.

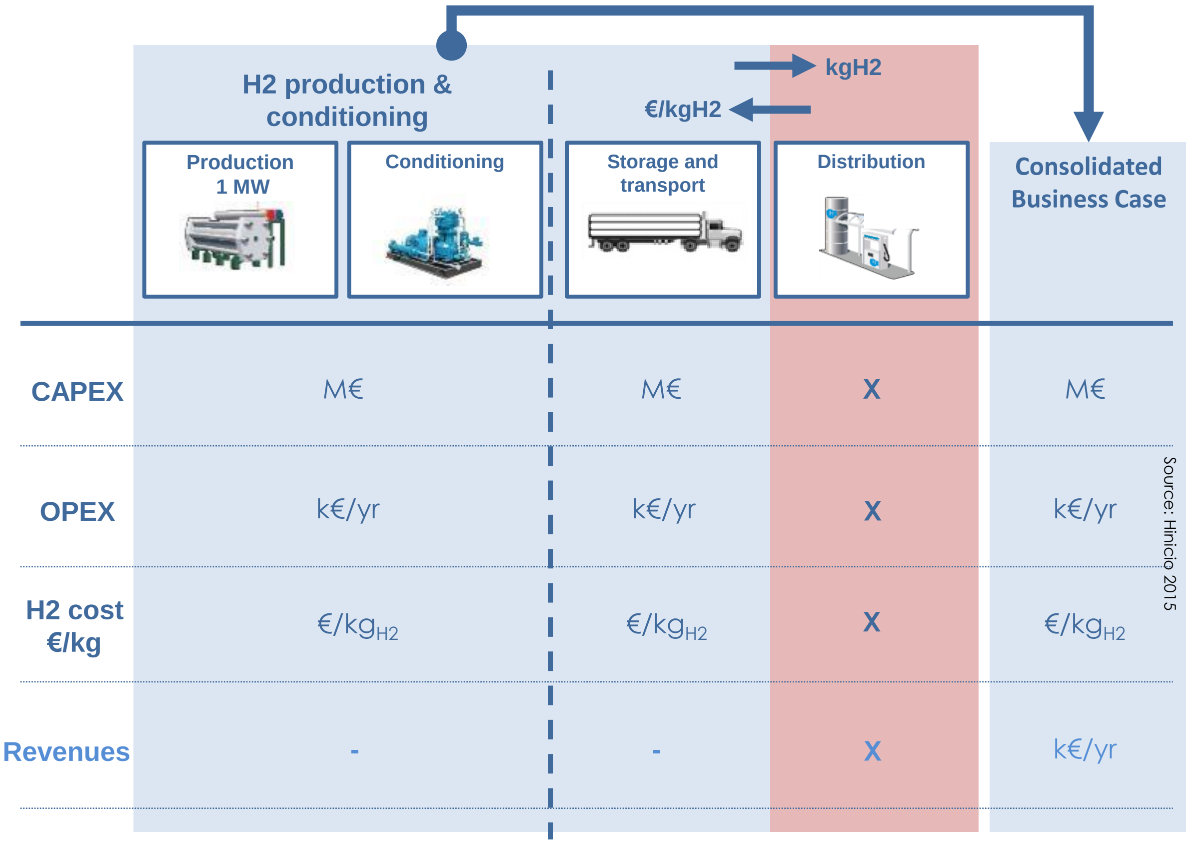

Figure 35: The different components of the semi-centralised PtH2 value chain and their price and revenue components (source: Hinicio)

System dimensioning: starting from the demand

In theory, the electrolyser is dimensioned to satisfy a given demand. However, to evaluate the business case for a given hydrogen production capacity, the electrolyser capacity was set at 1 MW. This corresponds to a daily market demand of 325 kg_{H2} assuming an electrolyser energy efficiency of 50 kWh per kg_{H2}, 95% availability, a performance decrease rate of 10% over the lifetime of the electrolyser and a required 25% excess capacity to cover losses of useable operating time due to the discontinuous nature of hydrogen logistics.

This daily demand is set to be met 10 years after the project is operational, starting from an initial demand of 100 kg/day.

The electrolyser location is set to ensure electricity and natural gas grid interaction, to answer hydrogen needs within a given area and to optimise operations and logistics. In the case under scrutiny, the electrolyser is assumed to satisfy demand within a 50 kilometre radius. Two distribution points are assumed to regroup the local hydrogen demand. These are situated at 40 and 20 kilometres from the point of production.

Costs and revenues of the electrolyser and hydrogen conditioning centre

Capex

The investment cost of the 1 MW installed capacity PEM electrolyser, in 2015, is estimated at 1.9 M€ and, at the 2030 horizon at 0.55 M€. The hydrogen production unit further includes a compressor and an injection skid which bring total investment costs at 2.5 M€ in 2015 (excluding installation costs). By 2030, total cost of these technologies is considered to have decreased as a result of market uptake to 1.2 M€.

Opex

The main operational cost of producing hydrogen is the cost of electricity. Two different means of procuring electricity are taken into consideration. Either electricity is purchased on the spot market or it is purchased directly from an intermittent onshore wind energy producer via a take or pay fixed fee contract (for further details on the price of electricity based on the price duration curve, see section 3.3.1a)).

Hydrogen production also incurs operation and maintenance costs. These are assumed to be fixed and are set at 6% of capital costs per year.

Revenues

Revenues generated for the production of hydrogen come from three sources: hydrogen sales for mobility, the injection of hydrogen into the natural gas grid and the ancillary services the electrolyser provides to the electricity grid. Hydrogen injection into the natural gas grid is assumed to benefit from an injection tariff which is set at 90 €/ MWh. The price for providing system services is estimated to be at 18 €/ MW per hour.

Hydrogen storage and distribution system

To dimension the hydrogen storage and distribution system, the model follows a 3-step method. First, the size of storage at each distribution point is determined by calculating the optimum considering the cost of delivering the hydrogen from the point of production to the individual demand point and the per kilogram cost of a storage capacity unit. In the model, the optimum leads to a delivery every 3 to 4 days at full trailer capacity. Second, the trailer capacity is set. It is chosen in order to ensure that the filling time at the point of production is less than one day. Finally, the number of trailers is calculated based upon the average time required to complete a total delivery cycle (trailer filling, hydrogen transport and delivery to demand point, return to the production unit, and preparation for refill) and the required daily demand divided by the trailer capacity. For the first project year, a single 200 kg trailer is sufficient to answer daily demand. However, when full electrolyser capacity is reached, 3 tube trailers are required.

Costs and revenues of logistics and storage

Capex

The investment cost for the trailer depends on the number of required trailers multiplied by the cost of one trailer. The cost of a 200 kg capacity trailer is considered to be 125 k€. The capital investment for the trailers therefore increases over the project lifetime from 125 k€ to 375 k€.

Storage capacity at points of delivery is assumed to be equal to 4 days of consumption, as derived from the optimal logistics calculation. The associated total annualised capital investment costs are 19.6 k€.

Opex

The operational cost for hydrogen transport is based on a fixed hourly rate and a fixed per kilometre rate. Based upon these prices, the cost of transporting the hydrogen to each point of demand is calculated. The total operational costs correspond to the total cost of delivery multiplied by the required number of deliveries which depend on the evolution of demand at each HRS station. The cost of delivery is set at 45€/hour and 1 €/km.

Revenues

The price of hydrogen sales at 300 bar is set at 8 €/kg at the point of delivery.

3.3.4 Semi-centralised power-to-hydrogen business case analysis results

To determine the conditions under which the semi-centralised hydrogen production system reaches an economic balance, 11 scenarios were developed, based upon a central scenario. In the following section, the scenarios providing the most useful insights are presented. These scenarios are grouped together in order to answer the following questions:

i) What is the impact of having the possibility of injecting hydrogen into the natural gas grid as opposed to a scenario where such an option is not available?

ii) What is the impact of choosing to purchase electricity via the spot market as opposed to purchasing electricity directly from an onshore wind energy producer via a fixed fee tariff?

iii) What is the sensitivity to regulatory tariff conditions and electricity prices?

iv) What is the business case for the semi-centralised power-to-hydrogen system at the 2030 horizon?

The metric used to establish whether or not the power-to-hydrogen business case reaches economic balance is the project's Internal Rate of Return (IRR) over the first 10 years of operation -i.e. that is to say the length of time assumed for hydrogen sales to reach the demand level for which the electrolyser was dimensioned.

Following the explanation of the inputs and approach used for the construction of the reference scenario, the scenarios which answer the questions set hereabove are analysed.

The reference scenario

The reference scenario provides the meter against which to measure the other scenarios. Indeed, the reference scenario was constructed for the IRR to be equal to 0 thereby defining what the bottom-line conditions are to ensure the semi-centralised power-to-hydrogen business case are.

The results are presented under graphic form. For each year, t2 accumulated bars represent revenues and costs, respectively. The costs include grid services, injection market and H2 GoO sales. On the right hand side, the bar representing costs includes all the operational costs (hydrogen production and transport) fixed and variable costs as well as the capital investment costs. The capital costs are divided into the capital costs for logistics (trailers and storage) and the capital costs for hydrogen production (electrolyser, conditioning,). These capital costs are annualised over the first 10 years of the project.

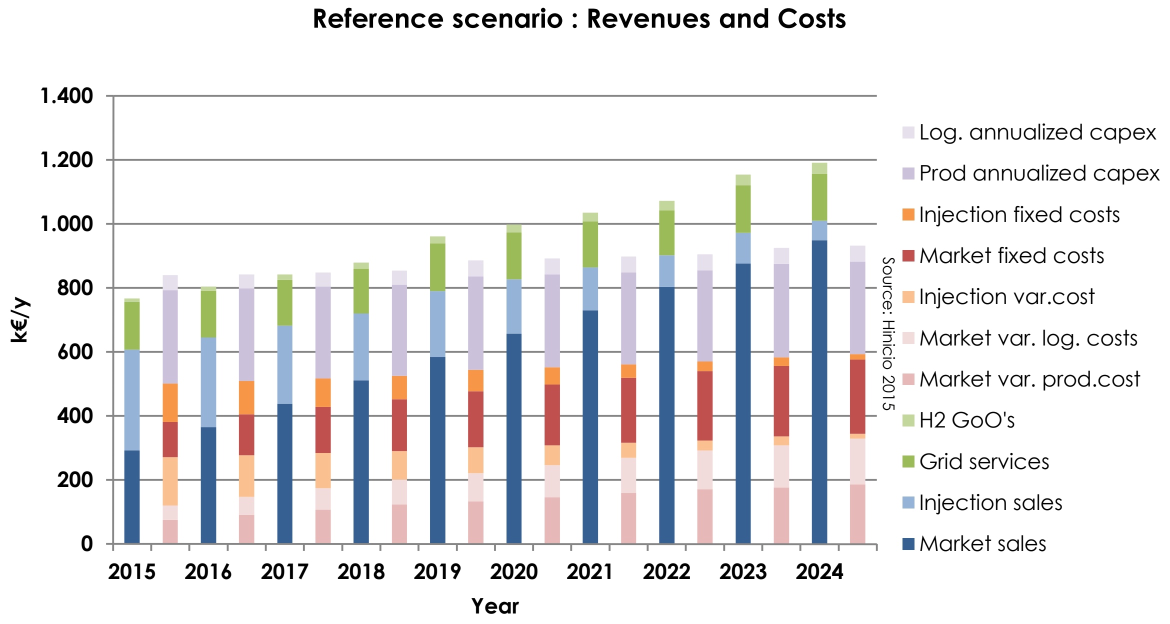

Figure 36: Example of scenario results graphic representation (source: Hinicio)

Reference scenario assumptions

In the reference scenario, hydrogen demand for mobility corresponds to our central assumption, namely, an initial demand of 100 kg/d in 2015 rising to 325 kg/d in 2025- an annual growth rate of 25 kg/d. The electricity price is based upon the French 2014 day ahead spot electricity price. A feed-in tariff for hydrogen injection of 90 €/MWh is assumed. The initial scenario is based upon the energy tax regime and tariffs currently in place in France and it is assumed that the electrolyser would benefit from the hyperélectro-intensif status which is to say that the contribution for the public service of energy (CSPE) is reduced to 0.5 €/MWh. Lastly, the electricity used to produce hydrogen for injection into the natural gas grid is exempt from any tax or grid charge[28].

In the reference scenario, the hydrogen mobility market consumes 1/3 of electrolyser capacity in 2015 which would correspond to the consumption of 100 passenger vehicles in commercial services. As the share of hydrogen for mobility rises, the hydrogen injected into the natural gas grid decreases, corresponding, in 2024, to 20% of the electrolyser capacity (residual capacity is assumed not to be usable for deliveries to the market due to the fact that this is a batch process). Between 2015 and 2024, the revenues from injection into the natural gas grid compensate for the global system investment and operating costs. With a FiT for hydrogen injection into the natural gas grid at 90 €/MWh, the electrolyser can produce hydrogen for injection the whole time as the maximum marginal cost of producing hydrogen (when electricity price is highest) is less than 90 €/ MWh. The ability to inject hydrogen into the natural gas grid complements the revenue streams during the project uptake phase when the fuel cell vehicle target demand is met. Additionally, this extends the electrolyser's operating time, thereby increasing the time during which it can provide frequency control services through increase or decrease of load by 100%[29], valued at 18 €/MW/h.

In both countries, the hydrogen producer is subject to paying taxes for electricity consumption and the use of the electricity grid. The tax and tariff burden varies depending on the country's regulation. In the case of Germany, the hydrogen producer must pay a 70 €/MWh fee to support the deployment of renewable energy technologies but is exempt from paying a grid use fee. In France, total energy consumption taxes were estimated at 39.3 €/MWh or at 20.3 €/MWh depending whether the electrolyser benefits from the tax exemptions associated to the hyperélectro-intensif status or not. In the first case, the tax for the contribution to the public energy service (CSPE*)* is set at the 2014 level of 19.5 euros per MWh. However, with the hyperélectro-intensif status, this tax rate is reduced to 0.5 €/MWh.

The figure below represents the costs and revenues for the reference scenario on the entire project lifetime.

[28] The justification of this being that injection into the natural gas grid helps serves the grid by helping to achieve balance without generating any additional cost for the grid operator.

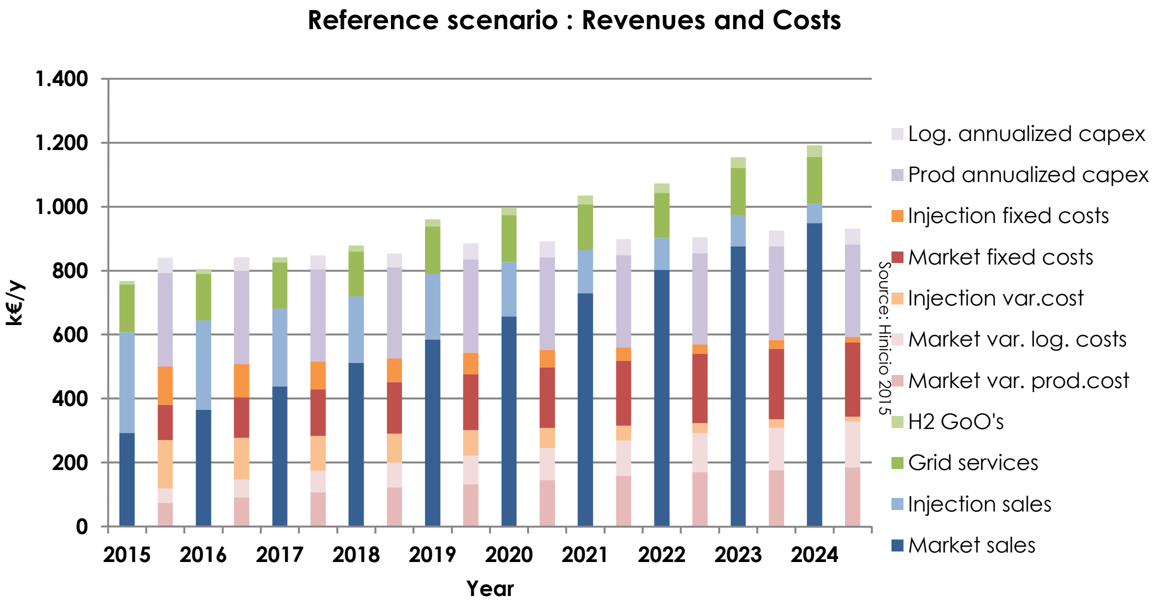

Figure 37: Reference Scenario: Revenues and Costs (source: Hinicio)

The reference scenario illustrates the advantage of having alternative revenue streams from hydrogen injection into the natural gas grid and by providing grid services to compensate for the limited market demand for hydrogen. An economic equilibrium for a semi-centralised power-to-hydrogen system could be made in France if economic-support measures were put in place; namely, an injection FIT for hydrogen of 90 €/MWh, the possibility of the electrolyser to benefit from the tax rebates associated to the hyperélectro-intensif status and an exemption for electricity grid fees and taxes for electricity used to produce hydrogen injected into the grid.

But what is the impact on the business case if such an option were not available? The following 2 scenarios seek to address this issue.

Natural gas injection or not

In both these scenarios, market sales uptake is slower than in the reference scenario, increasing annually by 7 kg/d instead of 25 kg/d. The first scenario presents the case with the possibility of injecting into the natural gas grid whilst the second presents the same case without this option.

The figure below presents the costs and revenues for the business case with low market demand but with hydrogen injection into the natural gas grid.

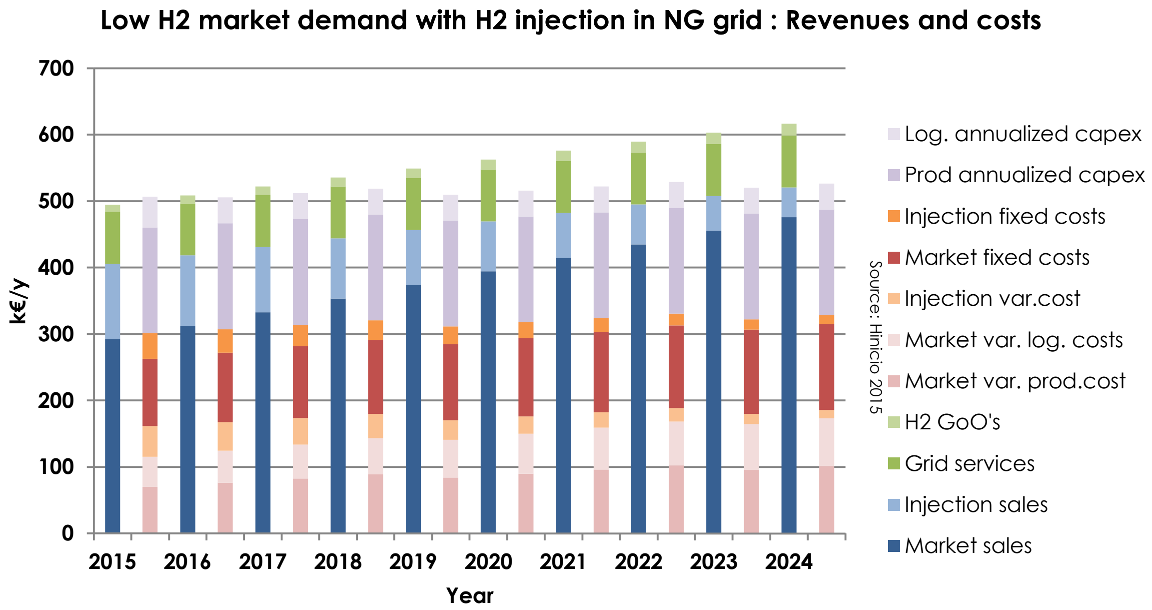

Figure 38: Low H2 market demand with H2 injection into the NG grid: Revenues and Costs (source: Hinicio)

The IRR -2% for the first 10 years of operation with a payback period of 11 years.

The figure below shows the costs and revenues for the business with low hydrogen market demand and without the possibility of injecting hydrogen into the natural gas grid.

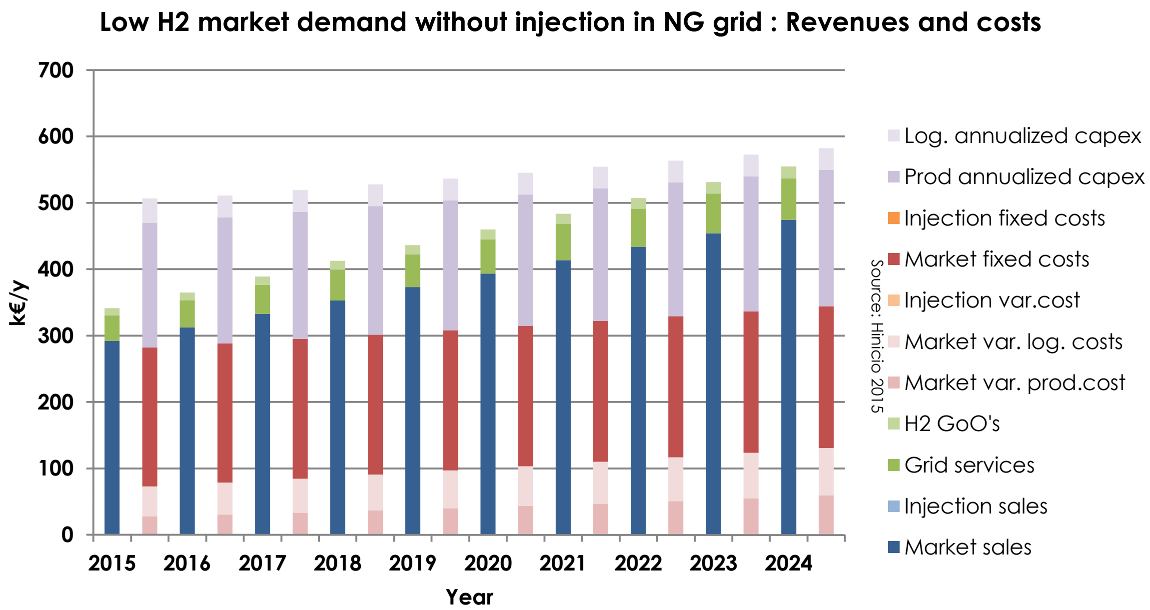

Figure 39: Low H2 market demand without injection into the NG grid: Revenues and Costs (source: Hinicio)

The IRR for this scenario is -12% with a payback period of 19 years.

First, it is worthwhile noting that slower market sales push back the break-even point by 1 year with hydrogen injection revenues. Considering a market growth rate less than 1/3 that of the reference scenario, the business case with the possibility of injection does not seem particularly affected by a less positive market evolution. This is because the reduction in hydrogen for mobility sales is compensated by increased revenues from the injection into the natural gas grid. In the second scenario (no injection) however, the revenue stream is entirely dependent on market sales. The amortization of initial investments requires 9 more years than the reference scenario. Hydrogen injection therefore reduces the risk associated to the market sales projection used to set the size the electrolyser.

Purchasing electricity directly from an onshore wind producer

Since the cost of electricity is a key variable in the cost of hydrogen production, would purchasing electricity from a producer via a take-or-pay contract improve the business case?

The second technical choice open to the electrolyser operator is the procurement of electricity. Because intermittent renewable energy producers are progressively subject to market rules, fixed fee long term electricity sales contracts are increasingly used by intermittent energy producers to ensure that their production is sold.

This scenario reflects the case where a fraction of the production of an on-shore wind farm is purchased through a take-or-pay agreement whilst maintaining all of the reference scenario's other characteristics. Figure 40presents the costs and revenues for the semi-centralised power-to-hydrogen system purchasing electricity directly from an onshore wind producer.

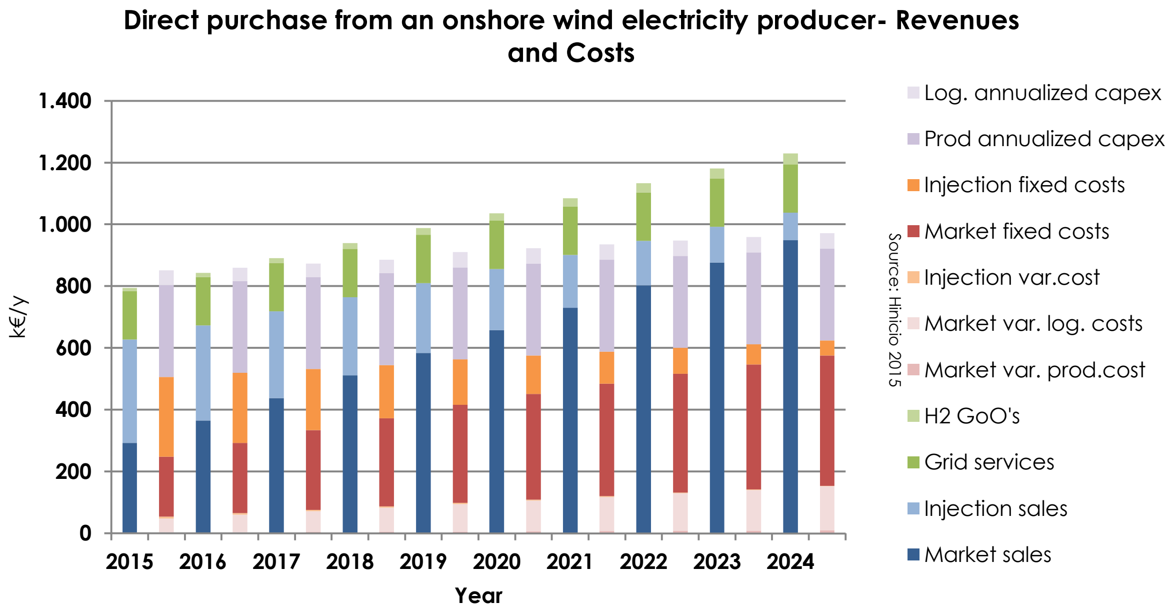

Figure 40: Direct purchase from an onshore wind electricity producer: Revenues and Costs (source: Hinicio)

To achieve breakeven point by year 10, the price of the contracted electricity must be 26 €/MWh i.e. 30% of the current total cost of electricity generated by an onshore wind turbine, estimated at 86.5 €/MWh. The discount would be justified by the fact that consumption would take place only when this electricity has the lowest market value. When comparing to the EPEX spot day ahead prices for France in 2014, prices were below 26 €/MWh for a little less than 2500 hours. The scheme provides greater security to the producer ensuring that all his production will be sold.

Such an agreement considerably modifies the cost structure of the power-to-hydrogen system. Indeed, the variable cost of production of hydrogen –which is mostly comprised of the cost of electricity- is greatly reduced. On the other hand, fixed costs are increased as the electricity is pre-purchased on a take-or-pay basis. For example, in 2020, total variable costs are approximately 10 k€ in this scenario, when, in the reference scenario, the corresponding cost is 225 k€/yr. The number of hours during which the marginal cost of hydrogen production is lower than the FIT is slightly increased compared to the reference case, increasing revenues from injection and grid services.

This modification in the cost structure of the project may also be worth pursuing in cases where the cost of capital is very low, for instance, in the case of public investment.

Applying the German market conditions

In order to establish the impact both of different grid tariffs and energy taxes as well as the sensitivity to the price of electricity, this scenario models the business case in the German context based on the 2013 spot market electricity prices. The end-user EEG appropriation for the financing of renewable energy in Germany are set at 70 €/ MWh. Figure 41presents the costs and revenues associated to this scenario over the project lifetime.

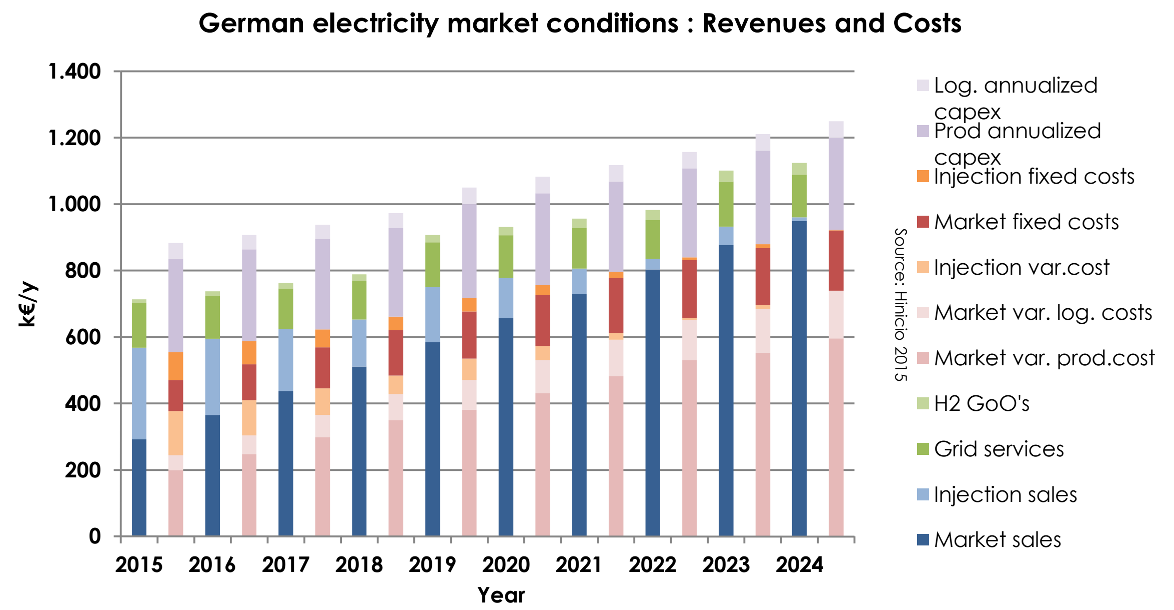

Figure 41: German electricity market conditions: Revenues and Costs (source: Hinicio)

Because of the high energy tax, the electricity price for which the injection FIT compensates hydrogen production is reached only for a limited number of hours, also resulting in less available time for providing grid services The limited number of running hours the electrolyser can produce hydrogen for injection coupled to the high variable cost of production lead to an IRR of -28%. Without exemption from the energy consumption tax regime, the project would require an injection FIT of 190 €/ MWh or a price of hydrogen for mobility of 9.5 €/kg (an 18% increase).

Power-to-hydrogen: the business case at the 2030 horizon in France and Germany

This scenario evaluates the business case at 2030 horizon whilst purchasing electricity directly from a wind energy producer. A number of further assumptions, replicating best-guess estimations as to future evolutions by 2030 structure this scenario. In 2030, market deployment has led to a significant decrease in the price of a 1 MW PEM electrolyser (from 1.9 M€ in 2015 to 0.55 M€ in 2030). Research and development efforts have improved the PEM electrolyser efficiency from 66% to 75% as well as stack lifetime from 4 to 10 years. The FIT for injection no longer exists as such, but the price of carbon and increased price of natural gas provide a low carbon premium for hydrogen injection worth 55.8 €/MWh[30]. Electricity produced via onshore wind turbines has dropped to 60 €/MWh. The projected electricity requirement is purchased upfront at the full cost of production for a wind turbine which is connected to the hydrogen production system but not to the electricity grid. As a result, assuming current conditions hold, the grid tariffs and taxes paid by the wind power producer would be 0 €.

Figure 42 presents the costs and revenues associated with this scenario.

[30] This value is based upon the IEA's 2030 estimation of the price of gas combined to the projected cost of carbon for natural gas.

Direct Purchase from an onshore wind electricity producer in 2030: Revenues and Costs

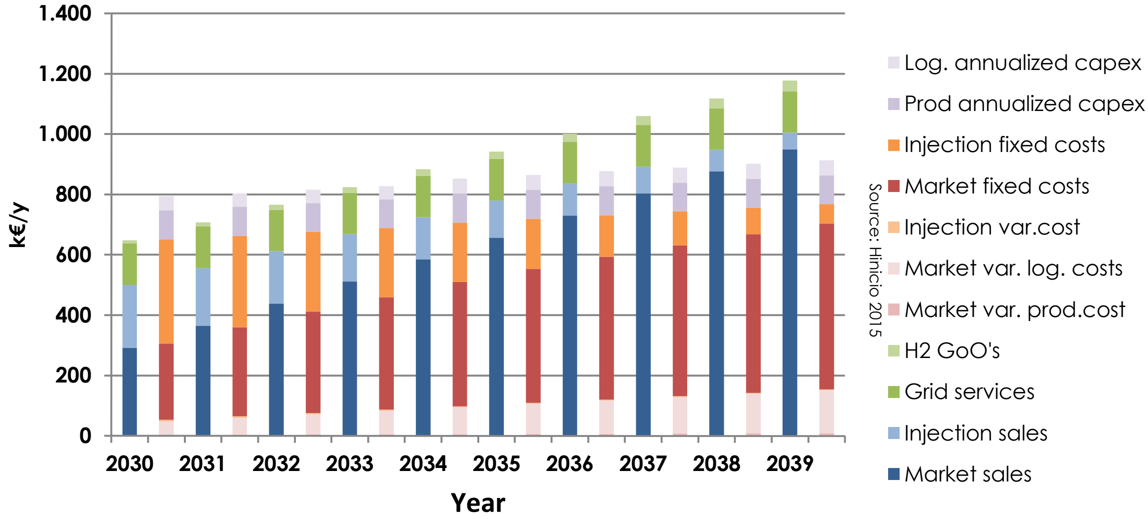

Figure 42: Direct purchase from an onshore wind electricity producer in 2030: Revenues and Costs (source: Hinicio)

With an IRR of 0%, this scenario demonstrates the impact of technological improvements and the future potential which the semi-centralised hydrogen production system may hold.

A scenario pendant to the one above, estimates the business case at 2030 horizon with the same technological and cost evolution but with electricity purchased on the spot market assuming the 2030 price duration curve calculated for Germany along with the taxes currently applicable in that country.

2030 horizon electrolyser characteristics with spot market electricity purchase:- Revenues and Costs

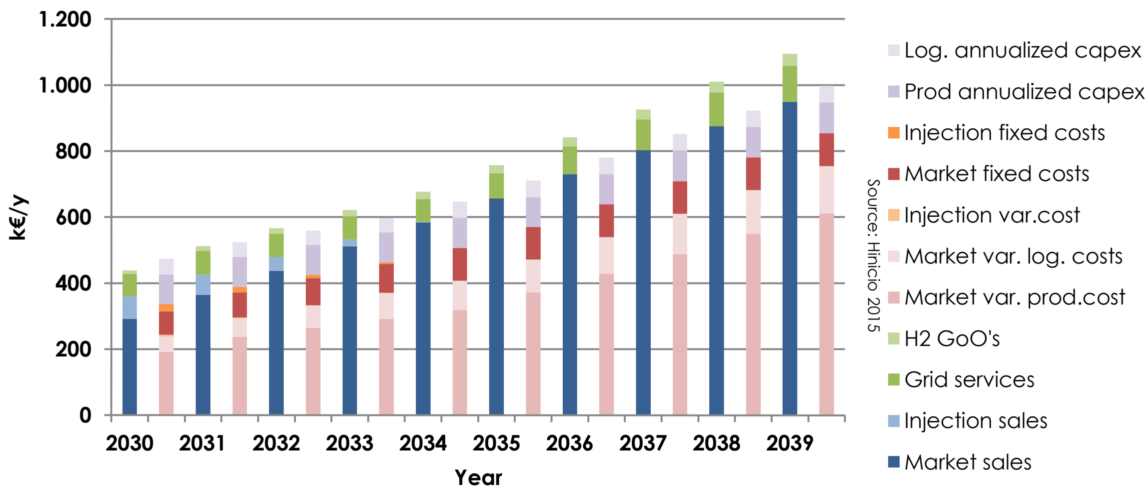

Figure 43 represents the costs and figures of the system at the 2030 horizon, supposing technological improvement and that electricity is purchased from the spot market.

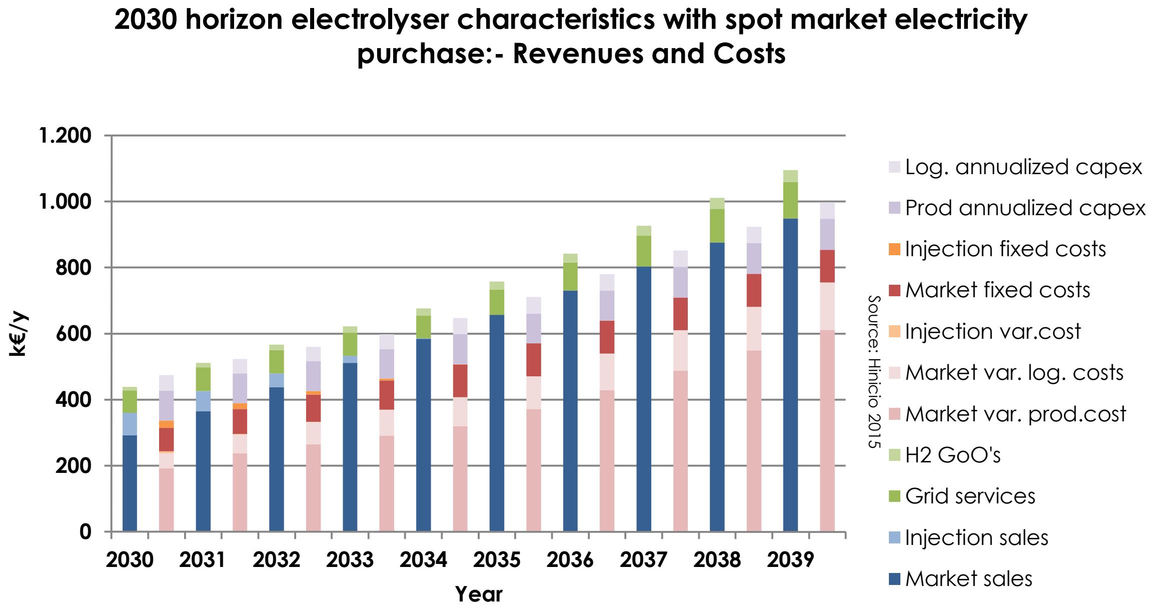

Figure 43: 2030 horizon electrolyser characteristics with spot market electricity purchase: Revenues and Costs (source: Hinicio)

Although the variable cost of hydrogen production remains high (4.52 €/kg in 2020 as compared to 1.92 €/ kg in the reference scenario), the capital cost, as a result of the increased stack lifetime and the electrolyser's improved efficiency, is considerably decreased. Indeed, in the reference scenario, the annualised capital cost is 297 k€/ year, whereas it is approximately 90 k€/year for this scenario. This change in the cost structure leads to an IRR of 0% over the first ten years of the project. This scenario demonstrates that with technological improvements high variable costs can be overcome, even without an injection FiT and could, on the basis of the assumptions, make the business case balanced at 2030 horizon in Germany.

3.4 Conclusions from the semi-centralised power-to-hydrogen business case analyses

3.4.1 Conclusions

From the results of Application B "Semi-centralised power-to-hydrogen system-business case studies", the following conclusions can be drawn:

- Assuming the application of a certain number of favourable regulatory conditions which are considered defendable[31], achieving economic balance seems feasible for short-term deployments in France; therefore, with some further support, for instance in the form of investment subsidies, such deployments could attract private investment.
- The French fee regime -applied as assumed above in this study-, would be particularly favourable for power-to-hydrogen. In contrast, the grid fee regime currently applied in Germany handicaps power-to-hydrogen. In the short-term, the study concludes that the economics of power-to-hydrogen are therefore more attractive in France rather than in Germany.
- Injection into the natural gas grid can generate two complementary revenue streams – from sales to the gas grid, and from services to the power grid performed when injection is taking place - which reduces exposure to uncertainty of revenues from the hydrogen market.
- A potentially attractive alternative to purchasing the needed electricity on the spot market is to contract its supply directly from a renewable power producer. Since consumption would take place only when this electricity has the lowest market value (i.e. during the hours for which the spot market prices are typically extremely low), the producer could accept a high level of discount for supply under such conditions, in return of visibility on the sales price. In the short term, a power-to-hydrogen system could afford to pay 30% of the full cost of renewable electricity under such a scheme.
- The study shows that an economic balance could potentially be achieved in both market environments and without public financial support by 2030 thanks to technological improvements[32].

3.4.2 Recommendations

Based on the results and conclusions from the analysis of the potential role semi-centralised power-to-hydrogen, the study authors recommend to:

- Create a feed-in tariff for the injection of green or low-carbon hydrogen into the natural gas grid of a level comparable to that of biomethane in France;
- In France, grant the hyperélectro-intensif status to hydrogen power-to-gas production;
- In Germany, provide similar tax, EEG appropriation, and grid fee benefits to hydrogen production by electrolysis as the hyperélectro-intensif status;
- In Europe, further develop sustainability criteria, certification procedures and accountability of green or low-carbon hydrogen towards EU targets, especially

[31] Exemption of grid fees and taxes for the electricity used to produce low-carbon hydrogen that is injected into the natural gas grid, a feed-in-tariff comparable to that applied to biomethane, and application of the conditions (exemption of grid fees) that are applicable to "electro-intensive" facilities.

[32] These technological improvements are an increase in electrolyser efficiency, the extension of stack lifetime and the reduction of electrolyser capital costs.

with regard to the EU Renewable Energies Directive (RED) and the EU Fuel Quality Directive (FQD);

- Exempt electricity used to produce green or low carbon hydrogen injected into the natural gas grid from grid fees and energy taxes;
- Financially support the implementation of supplying hydrogen to fuel cell electric vehicles.

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ANNEX

A1 TECHNOLOGY READINESS LEVEL (TRL)

In order to describe the state-of-the-art for technologies, the EC has introduced so-called "Technology Readiness Levels" 1-9 which are defined in Table 31.

Table 31: Definition of technology readiness levels (TRLs) according to HORIZON 2020 [EC-RTD 2014]

Technology Readiness Level (TRL)	Definition
1	Basic principles observed
2	Technology concept formulated
3	Experimental proof of concept
4	Technology validated in lab
5	Technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
6	Technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
7	System prototype demonstration in operational environment
8	System complete and qualified
9	Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)